Sixth International Williston Basin Horizontal Well Workshop

Sponsored by:

North Dakota Geological Survey

Saskatchewan Energy and Mines

May 3-5, 1998
Radisson Inn
Bismarck, North Dakota
USA

STATE OF NORTH DAKOTA
OFFICE OF THE GOVERNOR
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EDWARD T. SCHAFER
GOVERNOR

GREETINGS

TO THE PARTICIPANTS OF THE

SIXTH INTERNATIONAL WILLISTON BASIN HORIZONTAL WELL WORKSHOP

MAY 3-5, 1998
BISMARCK, NORTH DAKOTA

As governor of the great State of North Dakota, it is my pleasure to welcome you to North Dakota and the Capital City for the *Sixth International Williston Basin Horizontal Well Workshop*. My special thanks to the North Dakota Geological Survey and Saskatchewan Energy and Mines for hosting what promises to be an informative and enjoyable conference. I would also like to welcome the speakers and presenters at the Workshop. Your insights and information are valuable resources for everyone who is interested in oil production in North Dakota, as well as the surrounding areas, and the Canadian provinces.

For the most efficient and effective development of oil and gas reservoirs in the state and provinces, the newest and most innovative techniques in exploration and production must be used. Whether you are representing industry concerns, academic pursuits, or a government agency, this workshop provides opportunities to discuss a wide range of issues with those involved in the continuing exploration and development of the Williston Basin.

Best wishes for an enjoyable and worthwhile Workshop!

Sincerely,

Edward T. Schafer
Governor

Saskatchewan
Energy and Mines

A MESSAGE FROM

SASKATCHEWAN ENERGY AND MINES

On behalf of Saskatchewan Energy and Mines I would like to welcome you to the Sixth Williston Basin Horizontal Well Workshop and the second held in Bismarck.

As many of you are aware, the original intent of the Workshop was to promote business opportunities on both sides of the border as well as stimulate technology transfer. As registration levels grow, one could suggest that we have achieved success in both of these workshop goals. We hope that you take advantage of the workshop to renew acquaintances and to learn more about horizontal wells and opportunities in the Williston Basin.

I trust that you will enjoy the Workshop and your stay in Bismarck.

Ray Clayton
Deputy Minister
Saskatchewan Energy and Mines

April, 1998

Acid-free Paper

100-06112/

Sixth International Williston Basin Horizontal Well Workshop

List of Sponsors

We sincerely thank our industry sponsors for their generous support to help make this a successful meeting!

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Tuesday Morning Coffee Break
is sponsored by:

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GeoGraphix

Table of Contents

Agenda iii

Horizontal Well Activity Updates

Horizontal Drilling Activity in Manitoba ..... A
John N. Fox (Manitoba Energy and Mines)

Montana Horizontal Drilling Update ..... B
Larry N. Smith (Montana Bureau of Mines and Geology)

North Dakota Horizontal Drilling Update C
Bruce E. Hicks (North Dakota Industrial Commission - Oil & Gas Division)

South Dakota Horizontal Drilling Update ..... D
Gerald (Mack) McGillivray (South Dakota Dept. of Environment and Natural Resources Oil & Gas Program)

Engineering Topics

Horizontal Drilling: Technical Success but a Legal Quagmire ..... E
E. Craig Lothian (Gerrand Rath Johnson, Barrister Solicitors)

Enhanced Oil Recovery Using Carbon Dioxide: "The Decision Process" and Review of the Williston Basin CO_2 Pipeline Project ..... F
Ray P. Hattenbach (Dakota Gasification Company)

CO_2 Injection in Light and Medium Oil Reservoirs ..... G
Sam Huang (Saskatchewan Research Council)

Sidetracking in a Single Trip ..... H
*Greg Miller (Smith Drilling and Completions)
Charles Dewey (Smith Drilling and Completions)
James Saylor (Smith Drilling and Completions)

Grant Rotating Drilling Heads: History and Applications I
G. G. (Gary) Hanke (Smith International Canada, Ltd.)

Continuous Sucker Rod Reduces Costs ..... J
*Darren Wiltse (EVI Oil Tools-COROD)
Michael Fernandez (Stocker Resources, Inc.)

Multi-Zone Formation Pressure Testing During a Wiper Trip ..... K
*Paul Riggenberg (Halliburton Energy Services)
Neal Skinner (Halliburton Energy Services)

A Case History of Completing and Fracture Stimulating a Horizontal Well L
Peter Hagist (Pennzoil)
Hazim H. Abass (Halliburton Energy Services)
James Harry (Choctaw II Oil and Gas, Ltd.)
James L. Hunt (Halliburton Energy Services)
Mark Shumway (Choctaw II Oil and Gas, Ltd.)
Monte Besler (Halliburton Energy Services)

"The Dirt on Mud Loss": Interpreting Mud Loss Data From Mississippian Horizontal Wells in SE Saskatchewan ..... M
*Ken Wawro (Talisman Energy)
Mike Ware (Talisman Energy)

Geology/Geophysics Topics

Production Logging in Horizontal Wells .... N
*Joe Poole (Schlumberger Oilfield Services)
Troy Riggins (Schlumberger Oilfield Services)

Enhanced Recovery with Crosswell Imaging .... O
Bruce P. Marion (TomoSeis Inc.)

Mississippian Carbonates of the Williston Basin: Aspects of the Geology We Don't Understand .... P
John H. Lake (Lake Geological Services, Inc.)

The Upper Devonian Revisited .... Q
S. P. (Steve) Halabura (North Rim Exploration, Ltd.)

Petroleum Hydrogeology of the Upper Ordovician Yeoman Formation (Red River) in the Williston Basin .... R
*Dan Barson (Rakhit Petroleum Consulting, Ltd.)
Kaush Rakhit (Rakhit Petroleum Consulting, Ltd.)
Troy Meyers (Rakhit Petroleum Consulting, Ltd.)
Carlo Poletto (Rakhit Petroleum Consulting, Ltd.)
Shaun Cahoun (Rakhit Petroleum Consulting, Ltd.)

Horizontal Drilling Activity in the Ordovician Red River Formation of the Williston Basin: The Importance of Analogs .... S
Larry Kovac (Canadian Discovery Digest)

Controls on Deadwood and Winnipeg (Cambrian and Ordovician) Oil Production at Newporte Field, Renville County, North Dakota .... T
Michael L. Hendricks (Hendricks and Associates, Inc.)
Jacob D. Eisel (Eisel Oil)
David W. Fischer (Fischer Oil and Gas)

Miscellaneous Topics

Microbial Control of Paraffin, Scale, Corrosion, Emulsion, & Hydrogen Sulfide .... U
*Bill Botto (Micro-TES, Inc.)
Brent McCallick (Micro Well Services, Inc.)

Poster Abstracts

Landsat Lineament Zones in North Dakota .... PA
George W. Shurr (Dept. of Earth Sciences, St. Cloud University)

Mississippian Sherwood Shoreline Reservoirs As Horizontal Drilling Targets: Lucky Mound Field, McLean Co., North Dakota .... PB
Randolph B. Burke (North Dakota Geological Survey)

Exploration Trends South of the Border .... PC
Mary Bluemle (Minerals Diversified Services)

Core Display .... CD

Miscellaneous Information

Sixth International Williston Basin Horizontal Well Workshop

May 3- 5, 1998
Radisson Inn Bismarck
Bismarck, North Dakota, USA

Agenda

Sunday, May 3, 1998

5:00 pm **Registration Desk Open**

6:00 pm **Ice Breaker** (6:00 - 9:00 pm)

Monday, May 4, 1998

7:00 am **Speakers' Breakfast**

7:30 am **Registration**

8:00 am **Introduction, Welcome, and Opening Remarks: Saskatchewan/North Dakota Co-Chairpersons**
Malcolm Wilson (Saskatchewan Energy and Mines)
John Bluemle (North Dakota Geological Survey)

8:15 am ***Horizontal Drilling Activity in Manitoba***
John N. Fox (Manitoba Energy and Mines)

8:25 am ***Montana Horizontal Drilling Update***
Larry N. Smith (Montana Bureau of Mines and Geology)

8:35 am ***North Dakota Horizontal Drilling Update***
Bruce E. Hicks (North Dakota Industrial Commission - Oil & Gas Division)

8:45 am ***South Dakota Horizontal Drilling Update***
Gerald (Mack) McGillivray (South Dakota Department of Environment and Natural Resources Oil & Gas Program)

8:55 am ***Horizontal Drilling: Technical Success but a Legal Quagmire***
E. Craig Lothian (Gerrand Rath Johnson, Barrister Solicitors)

9:20am ***Enhanced Oil Recovery Using Carbon Dioxide: "The Decision Process" and Review of the Williston Basin CO_2 Pipeline Project***
Ray P. Hattenbach (Dakota Gasification Company)

9:45 am **Coffee and Refreshments - Poster Session**

10:45 am **CO_2 Injection in Light and Medium Oil Reservoirs**
Sam Huang (Saskatchewan Research Council)

11:10 am ***Sidetracking in a Single Trip***
*Greg Miller (Smith Drilling and Completions)
Charles Dewey (Smith Drilling and Completions)
James Saylor (Smith Drilling and Completions)

11:35 am ***Grant Rotating Drilling Heads: History and Applications***
G. G. (Gary) Hanke (Smith International Canada, Ltd.)

12:00 pm **Lunch: Addresses by North Dakota Attorney General Heidi Heitkamp, & the Honorable Eldon Lautermilch, Minister of Saskatchewan Energy and Mines**

2:00 pm ***Continuous Sucker Rod Reduces Costs***
*Darren Wiltse (EVI Oil Tools - COROD)
Michael L. Fernandez (Stocker Resources, Inc.)

2:25 pm ***Multi-Zone Formation Pressure Testing During a Wiper Trip***
*Paul Ringgenberg (Halliburton Energy Services)
Neal Skinner (Halliburton Energy Services)

2:50 pm **Coffee and Refreshments - Poster Session**

3:50 pm ***A Case History of Completing and Fracture Stimulating a Horizontal Well***
Peter Hagist (Pennzoil)
Hazim H. Abass (Halliburton Energy Services)
James Harry (Choctaw II Oil and Gas, Ltd.)
James L. Hunt (Halliburton Energy Services)
Mark Schumway (Choctaw II Oil and Gas, Ltd.)
*Monte Besler (Halliburton Energy Services)

4:15 pm ***"The Dirt on Mud Loss": Interpreting Mud Loss Data From Mississippian Horizontal Wells in SE Saskatchewan***
*Ken J. Wawro (Talisman Energy)
Mike Ware (Talisman Energy)

4:40 pm **Posters**

Tuesday, May 5, 1998

7:00 am **Speakers' Breakfast**

7:45 am **Registration**

8:00 am **Introduction, Welcome, and Opening Remarks: Saskatchewan/North Dakota Co-Chairpersons**
Malcolm Wilson (Saskatchewan Energy and Mines)
John Bluemle (North Dakota Geological Survey)

8:05 am **Address by North Dakota Commissioner of Agriculture Roger Johnson**

8:15 am *Production Logging in Horizontal Wells*
*Joe Poole (Schlumberger Oilfield Services)
Troy Riggins (Schlumberger Oilfield Services)

8:55 am *Enhanced Recovery with Crosswell Imaging*
Bruce P. Marion (TomoSeis Incorporated)

9:20 am *Mississippian Carbonates of the Williston Basin: Aspects of Geology We Don't Understand*
John H. Lake (Lake Geological Service, Inc.)

9:45 am **Coffee and Refreshments - Poster Session**

10:45 am *The Upper Devonian Revisited*
S. P. (Steve) Halabura (North Rim Exploration Ltd.)

11:10 am *Petroleum Hydrogeology of the Upper Ordovician Yeoman Formation (Red River) in the Williston Basin*
*Dan Barson (Rakhit Petroleum Consulting, Ltd.)
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Carlo Poletto (Rakhit Petroleum Consulting, Ltd.)
Shaun Cahoun (Rakhit Petroleum Consulting, Ltd.)

11:35 am **Lunch**

1:05 pm *Horizontal Drilling Activity in the Ordovician Red River Formation of the Williston Basin: The Importance of Analogs*
Larry Kovac (Canadian Discovery Digest)

1:30 pm *Controls on Deadwood and Winnipeg (Cambrian and Ordovician) Oil Production at Newporte Field, Renville County, North Dakota*
*Michael L. Hendricks (Hendricks & Associates, Inc.)
Jacob D. Eisel (Eisel Oil)
David W. Fischer (Fischer Oil and Gas)

1:55 pm *Microbial Control of Paraffin, Scale, Corrosion, Emulsion, & Hydrogen Sulfide*
*Bill Botto (Micro-TES, Inc.)
Brent M. McCallick (Micro Well Services, Inc.)

2:20 pm **Closing Remarks and Thank You**

3:00 - 7:00 pm **CORE DISPLAY** (Missouri Ballrooms, refreshments will be available)
Julie LeFever (North Dakota Geological Survey)
Tom Heck (North Dakota Geological Survey)

A

Horizontal Drilling Activity in Manitoba

John N. Fox
Manitoba Energy and Mines, Petroleum and Energy Branch

6TH INTERNATIONAL WILLISTON BASIN
HORIZONTAL WELL WORKSHOP

HORIZONTAL DRILLING ACTIVITY IN MANITOBA

Last year in Manitoba, 28* of the 109 wells drilled were horizontal. In 1997, horizontal wells accounted for 24.8% of the wells drilled and 38.5% of the drilling meterage in Manitoba, compared to the Western Canadian average of 12% of all completions. The average horizontal well depth was 1485 m, compared to 808 m for vertical wells. The average horizontal well took 9 days to drill and had a horizontal section length of 496 m.

Manitoba's leading horizontal drillers in 1997 were Chevron Canada Resources with 9 wells, followed by Rigel Oil and Gas with 6 wells and Canadian Natural Resources with 5 wells. During the first quarter of 1998, 7 horizontal wells were drilled, 6 by Tundra Oil and Gas.

The drilling of horizontal wells in Manitoba is increasing every year. To date, horizontal wells have been drilled in 32 different pools in 10 of Manitoba's 13 fields. Horizontal wells are not only being used successfully as infill wells between existing producers, but also to develop newly discovered pools, extend existing pool boundaries and to produce trapped oil in mature waterfloods.

The Lodgepole Formation was the favourite target in 1997 with 11 wells drilled, followed by the MC-1 with 7 wells. To date, the Lodgepole and MC-1 formations have been the target of 52 of the 77 horizontal wells drilled in Manitoba.

Horizontal well production has increased annually since 1992. In 1997, horizontal well production increased by 59% to 136,447 m^3 (858,650 bbls). In December 1997, 63 of the 77 horizontal wells drilled in Manitoba were on production. Production from these wells totalled 450 m^3 /d (2830 b/d), an average of 7.1 m^3 /d/well (45 b/d/well) and represented 23.4% of the provincial total. By comparison the average vertical well in Manitoba produces 1.0 m^3/d (6.5 b/d).

---

*includes one horizontal re-entry

Lodgepole and MC-1 horizontal producers accounted for 73% of horizontal well production in 1997. Horizontal producers located in the Pierson, Virden, Tilston and Daly Fields accounted for 74.8% of horizontal well production.

Normalized production for horizontal wells in Manitoba, determined by setting each well back to the same "time-zero", is characterized by a decline rate of 27.4%, from an initial rate of 15.0 m^3/d (94 b/d). Based on the limited production history for most Manitoba horizontal wells, the majority of which have produced for less than four years, the average well is likely to recover 18,650 m^3 (117,360 bbls).

In Manitoba, a horizontal well is defined as a well that achieves an angle of at least 80° from the vertical for a minimum distance of 100 m. To drill a horizontal well in Manitoba no special approval is required, only a well licence. Horizontal wells receive a HOV of 10 000 m^3 (62,930 bbls) or 10 years production, whichever comes first. Production from horizontal wells is classified as new oil. The value of the horizontal well incentive based on initial productivity of 15 m^3/d (94 b/d) and 20 m^3/d (126 b/d) both declined at 30% p.a. (exponential) is shown below.

Well Classification	Oil Price ($/$m^3$)	HOV (m^3)	Initial Production (m^3/d)	Value of Holiday Oil Volume	
				Crown Royalty	Production Tax
Horizontal	160	10000	15.0	$ 287,636	$ 190,178
Horizontal	160	10000	20.0	$ 323,538	$ 230,783

Where a horizontal well penetrates or drains more than one spacing unit, royalty and production tax is calculated per spacing unit based on production allocated to the spacing unit. The saving associated with paying royalty and production tax for a horizontal well, on a per spacing unit basis should not be overlooked. From the previous example, a well with initial productivity of 20 m^3/d (126 b/d) declined at 30% p.a. (exponential) will be producing 12.1 m^3/d (76 b/d) after production of the 10 000 m^3 (62,930 bbls) HOV. The Crown royalty rate on total well production would equal 22.8%, compared to 18.9% where the well penetrates or drains three spacing units and 16.9% where four spacing units are penetrated or drained. This translates into monthly royalty savings of $2295 for the three spacing unit case and $3472 for the four spacing unit case. Production tax savings of $2615 and $3936 per month are realized under the same conditions.

John Fox, P.Eng.
Chief Petroleum Engineer
Manitoba Energy and Mines
Petroleum and Energy Branch

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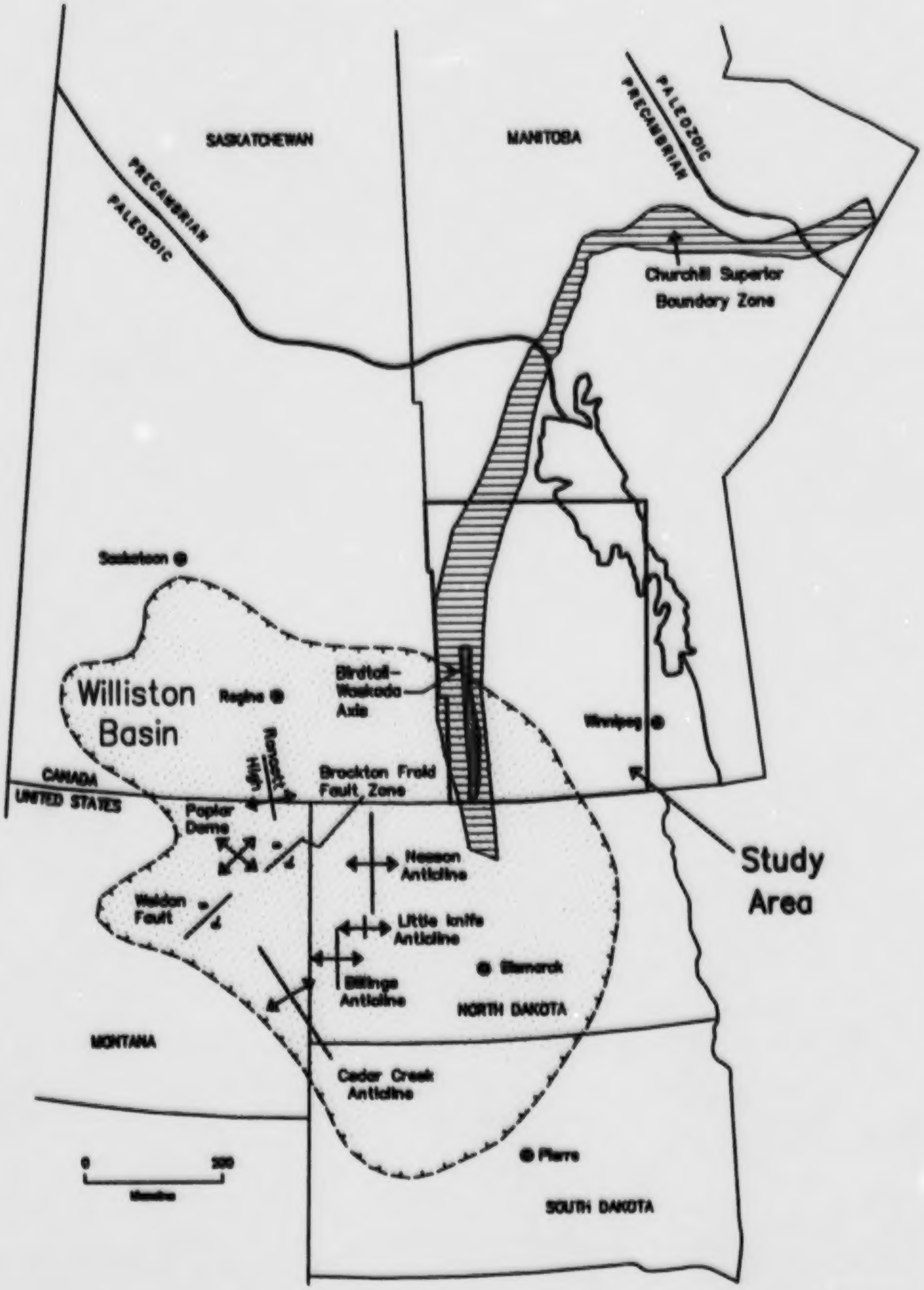
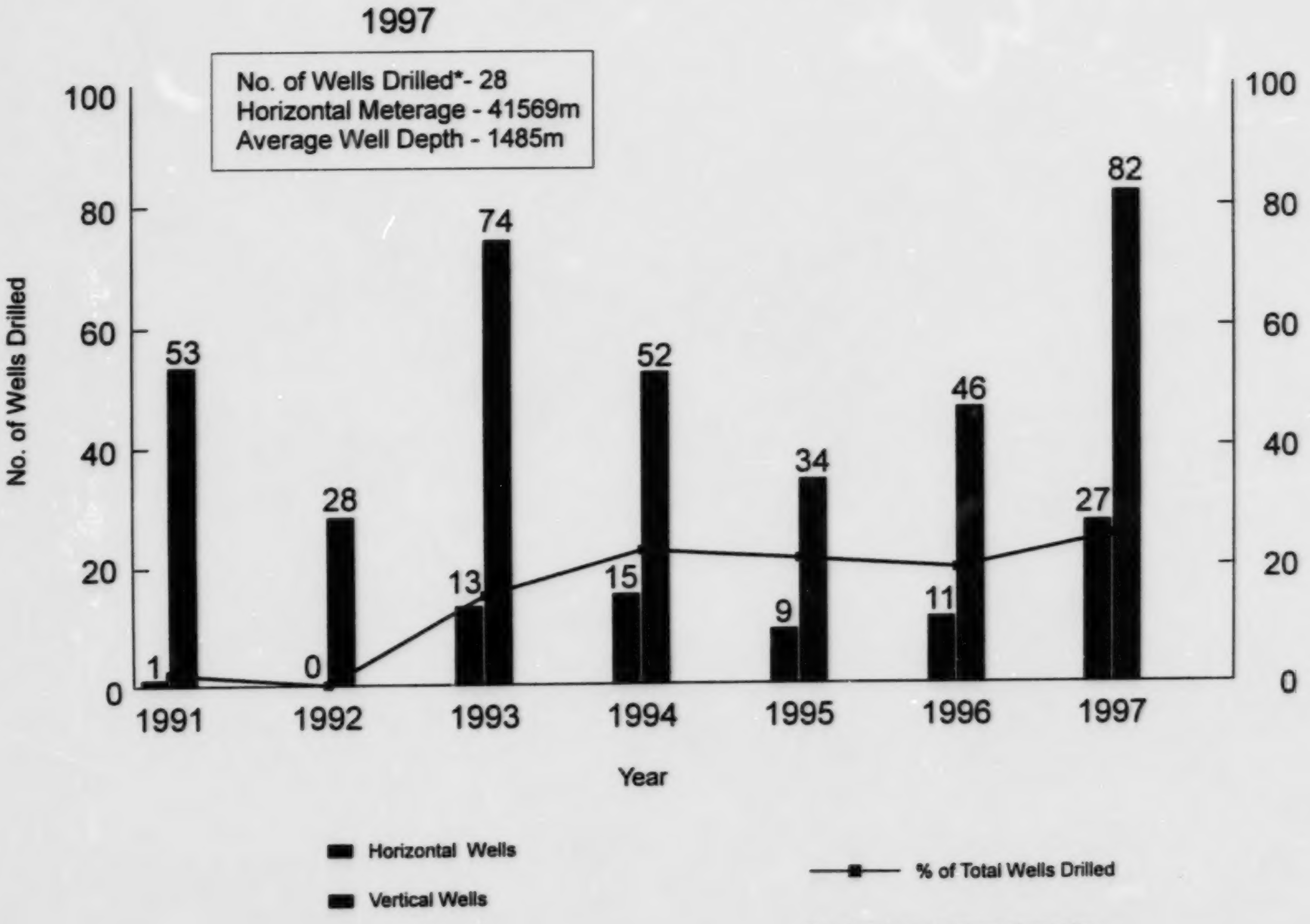

SASKATCHEWAN
MANITOBA
PRECAMBRIAN
PALEOZOIC
PALEOZOIC
PRECAMBRIAN
Churchill Superior
Boundary Zone
Saskatoon
Williston
Basin
Regina
Birdtail-
Waskada
Axis
Winnipeg
Nesson
High
CANADA
UNITED STATES
Brockton Froid
Fault Zone
Poplar
Dome
Study
Area
Nesson
Anticline
Weldon
Fault
Little knife
Anticline
Bismarck
Billings
Anticline
NORTH DAKOTA
MONTANA
Cedar Creek
Anticline
0
300
kilometre
Pierre
SOUTH DAKOTA

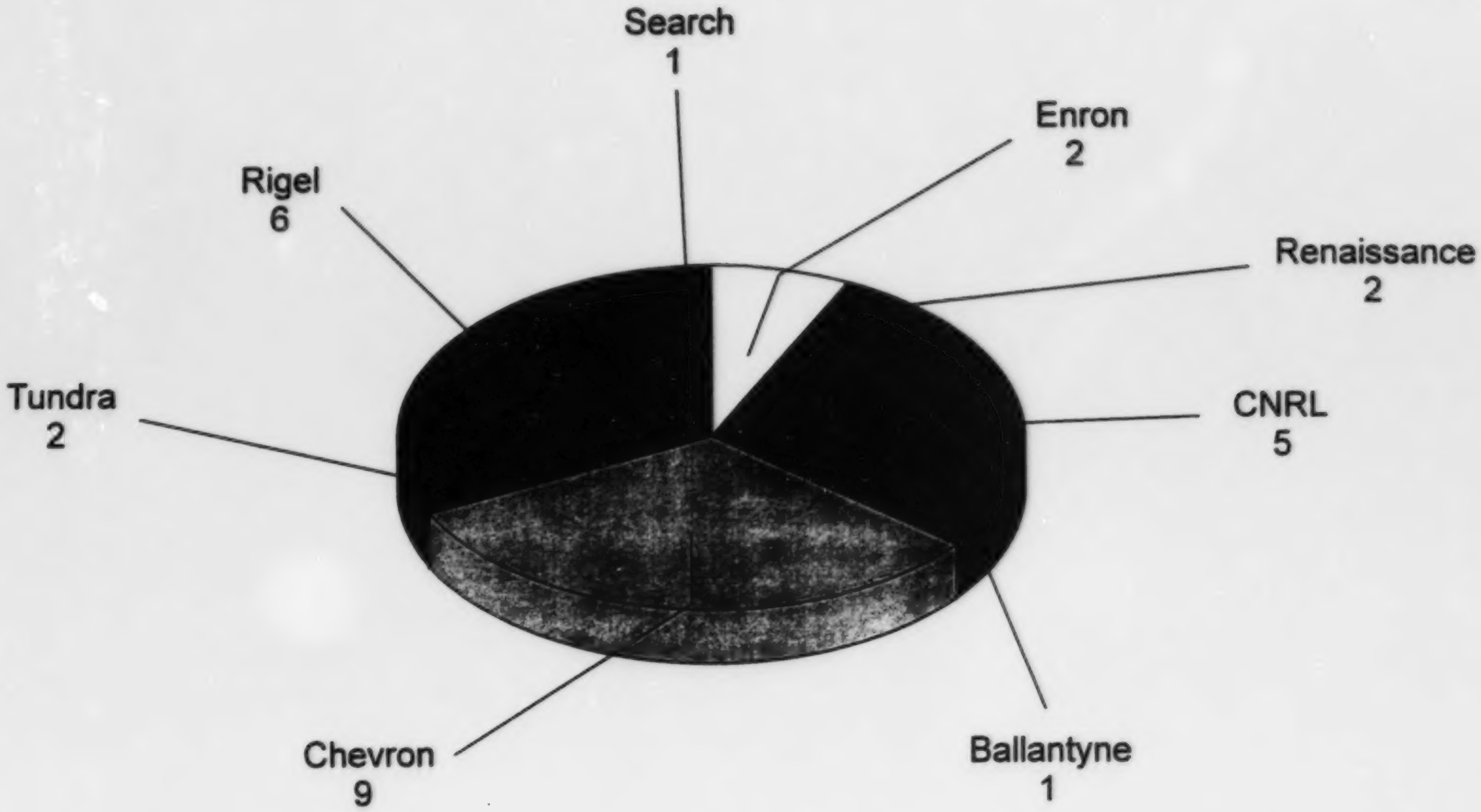
Map of the Williston Basin showing major structural features and study area for the Branch's recently released report: Regional Overview of the Geology and Petroleum Potential, Red River Formation, Southwestern Manitoba.

Manitoba Drilling Activity



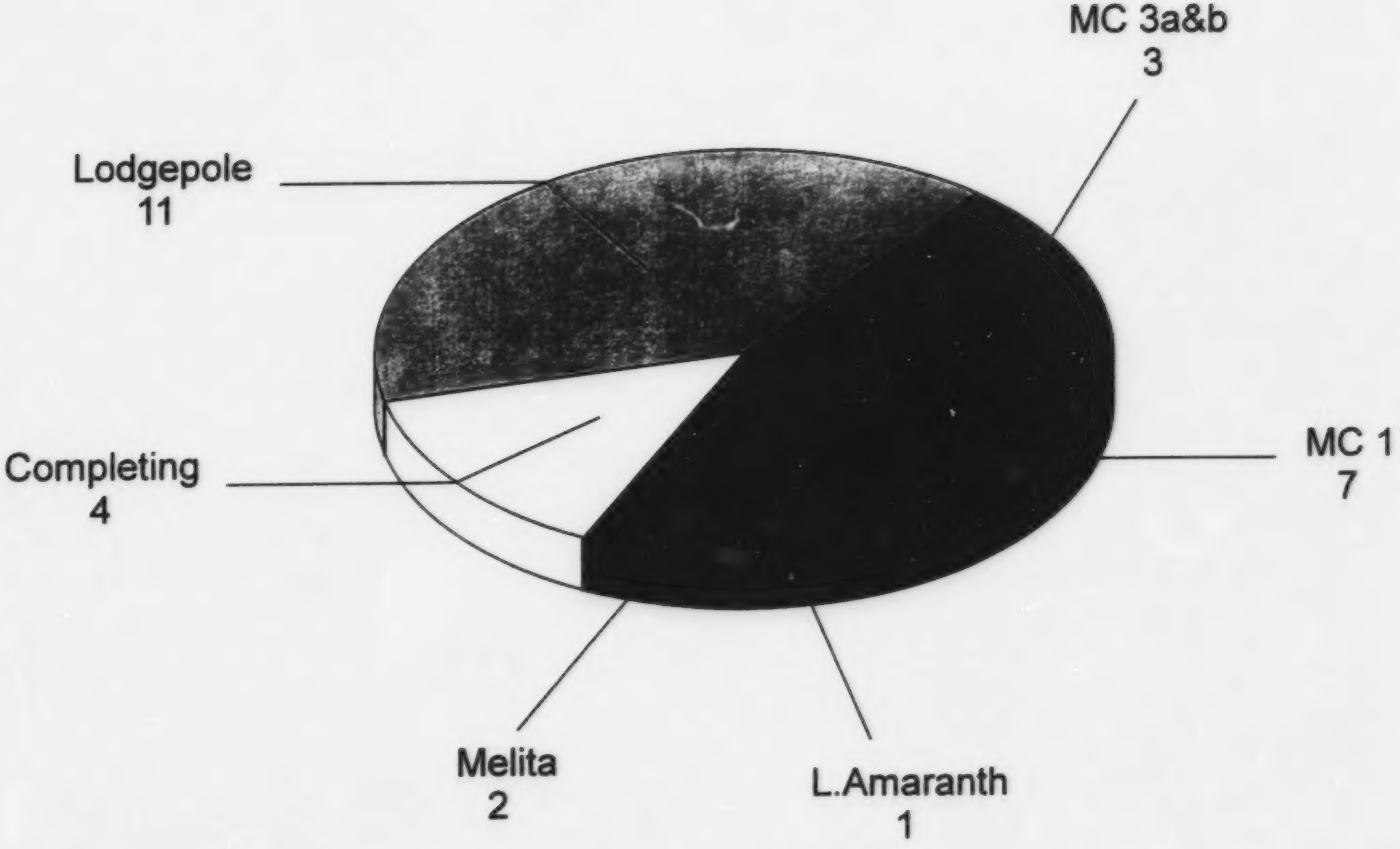
* includes one horizontal re-entry

1997 Horizontal Drilling by Operator



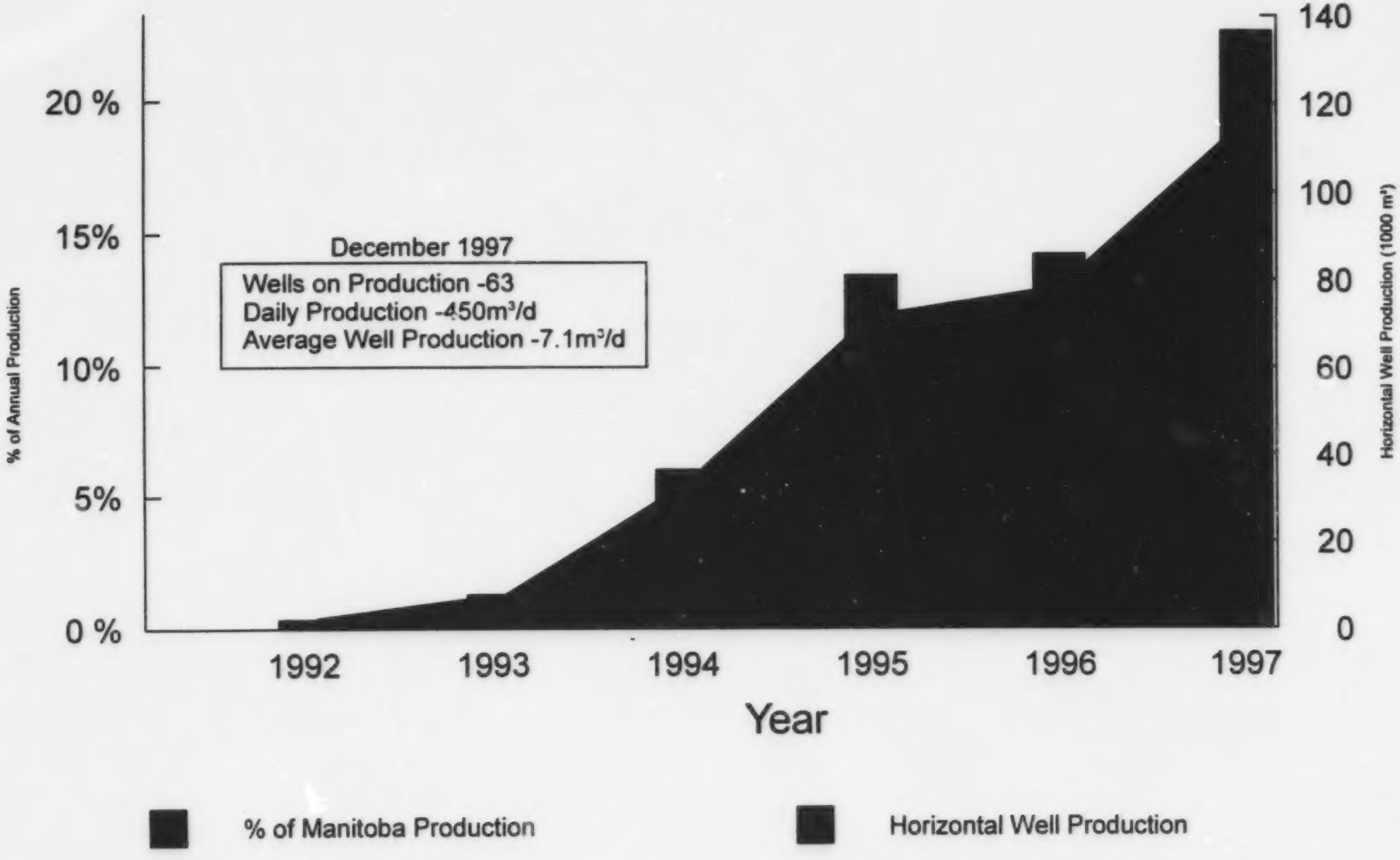
28 Horizontal Wells Drilled & Re -Entered

1997 Horizontal Drilling by Formation



28 Horizontal Wells Drilled & Re - Entered

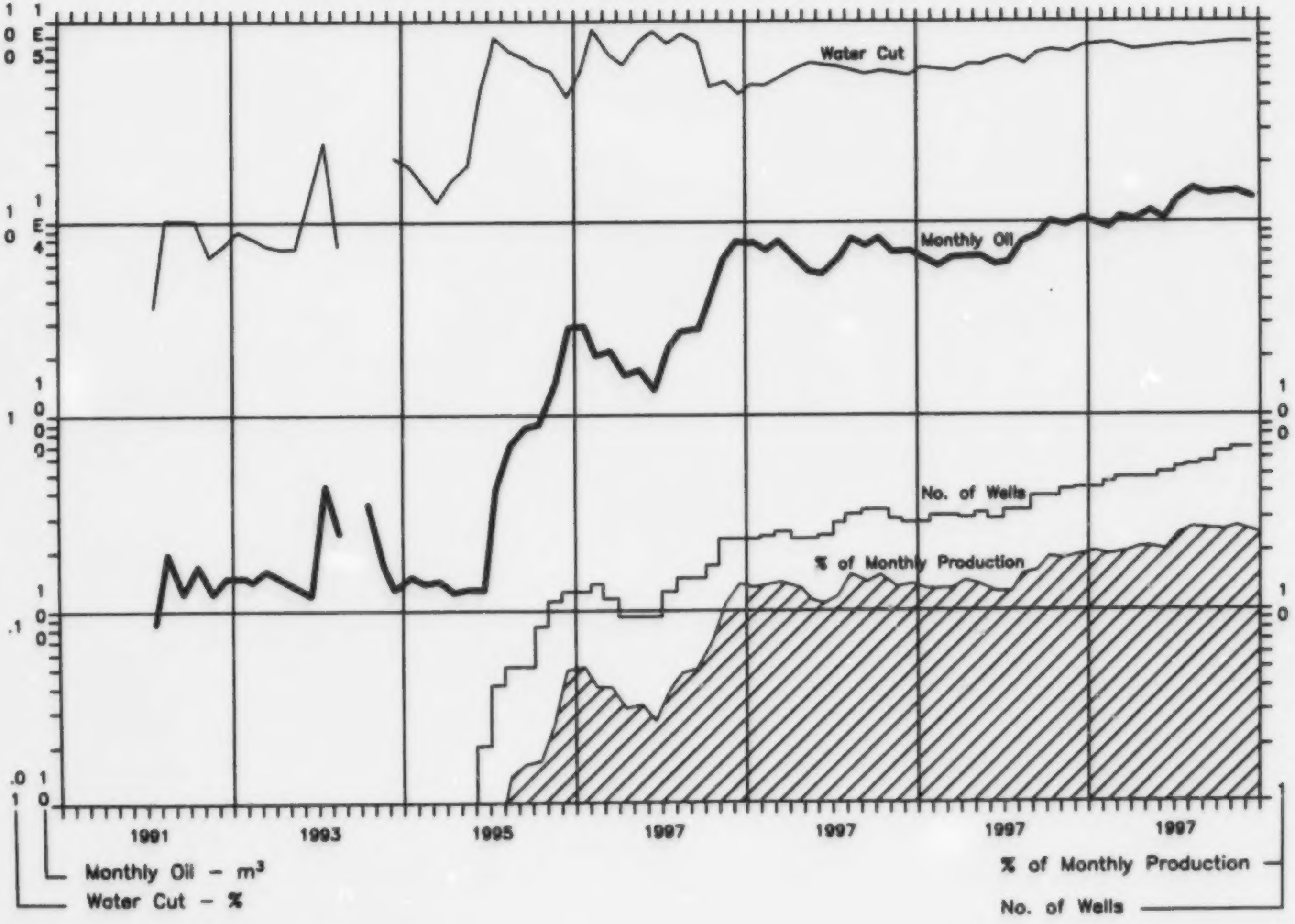
Horizontal Well Production



December 1997

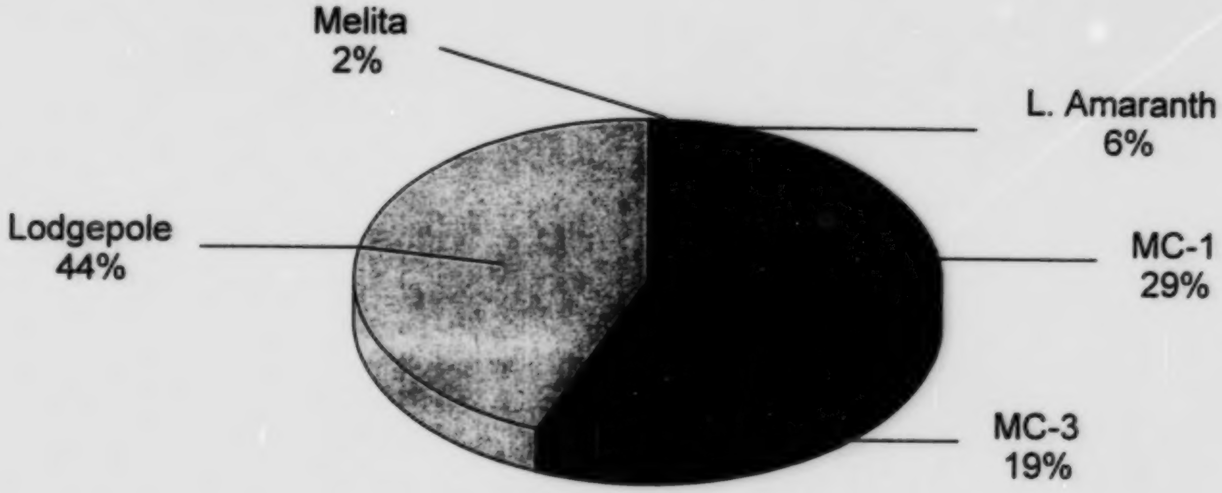
Wells on Production -63
Daily Production -450m³/d
Average Well Production -7.1m³/d

Horizontal Well Production 07/91–12/97



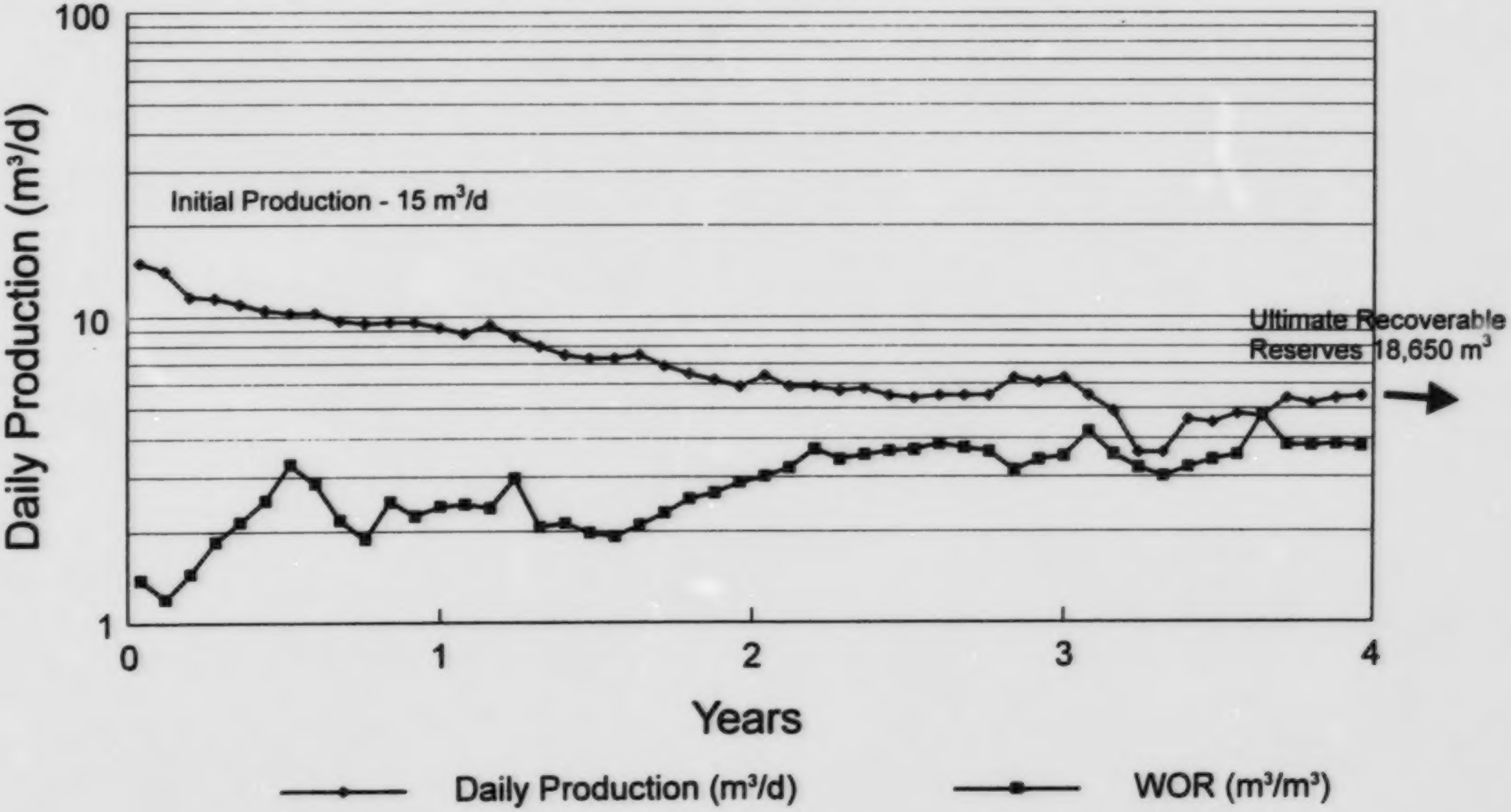
Horizontal Well Production by Formation

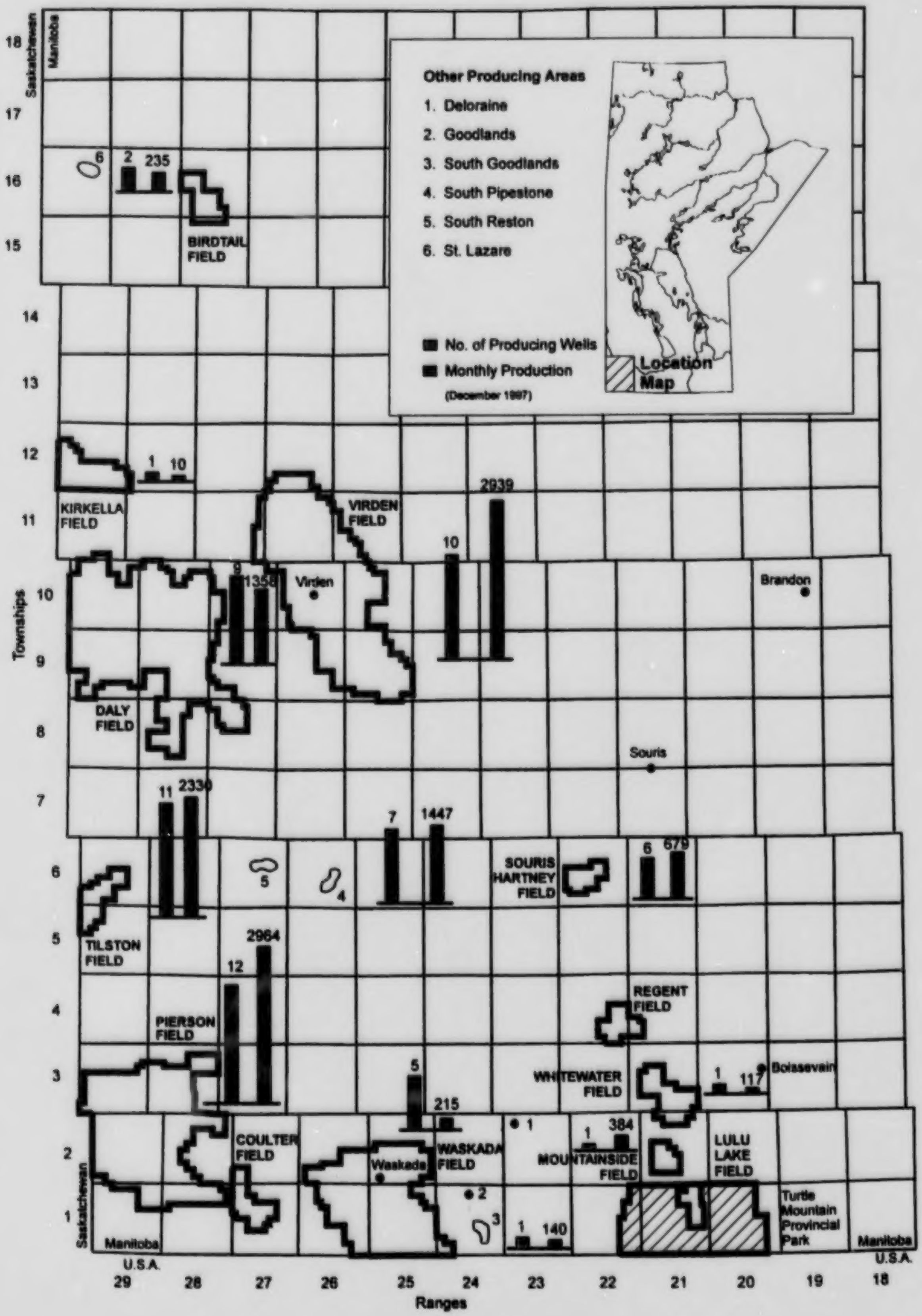
(Dec-97)



Average Production - 7.1 m^3/d/well

Normalized Horizontal Well Production




Other Producing Areas
1. Deloraine
2. Goodlands
3. South Goodlands
4. South Pipestone
5. South Reston
6. St. Lazare
No. of Producing Wells
Monthly Production
(December 1997)
Location Map
Saskatchewan
Manitoba
U.S.A.
Townships
Ranges
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
29
28
27
26
25
24
23
22
21
20
19
18
6
2
235
BIRDTAIL FIELD
1
10
KIRKELLA FIELD
VIRDEN FIELD
2939
10
9
1358
Virden
Brandon
DALY FIELD
Souris
11
2330
7
1447
5
4
SOURIS HARTNEY FIELD
6
679
TILSTON FIELD
12
2964
REGENT FIELD
PIERSON FIELD
5
WHITEWATER FIELD
1
117
Boissevain
215
1
1
384
COULTER FIELD
Waskada
WASKADA FIELD
MOUNTAINSIDE FIELD
LULU LAKE FIELD
2
3
1
140
Turtle Mountain Provincial Park

HORIZONTAL WELL DATA BY FORMATION

Formation	No. of Wells Drilled	Average MD(m)	Average Horizontal Interval (m)	Average Initial Production (m^3/d)	Recovery per Well	
					Current (m^3)	Ultimate (m^3)
MELITA	2	912	249	16.7	1875	6323
L. AMARANTH	7	2426	1290	15.2	5871	13031
MC - 3	14	1791	711	16.9	5894	13103
MC - 1	23	1580	606	23.1	7777	23472
LODGEPOLE	29	1347	567	10.1	3307	15943
CONFIDENTIAL	1	1073	-	-	-	-

ANNUAL MANITOBA HORIZONTAL WELL PRODUCTION SUMMARY

Mar. 5/98

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m³/d)	DAILY PRODUCTION Dec/97 (m³/d)	CUMULATIVE PRODUCTION (m³)	STATUS
Melita	4-22-16-29	Renaissance Energy	Other Areas Melita A	796	277	10.5	2.6	2 048.1	COOP
	A4-22-16-29	Renaissance Energy	Other Areas Melita A	784	226	7.8	5.1	1 701.7	COOP
		2nd Leg	KOP-610 m	854	244				
Lower Amaranth	7-15-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1871	624	4.3	-	-	
		2nd leg	KOP-1492 m	1805	313				
		3rd leg*	KOP-1270 m	1829	559	7.0	3.4	4 697.4	COOP
	11-11-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	2465	1283	15.5	6.5	13 356.6	COOP
	2-26-1-29	Williston Wildcatters	Pierson - L. Amaranth L	1652	408	-	SI	0.4	ABD PROD
	11-10-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1838	692	10.9	2.8	5 532.6	COOP
	9-25-1-26	NCE Petrofund	Waskada L. Amaranth A	1703	675	6.6	1.2	2 703.3	COOP
		2nd leg	KOP-1086 m	1675	589				
	2-19-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	2481	1353	16.8	6.6	8 754.1	COOP
		2nd leg	KOP-1164 m	1980	816				
	1-16-2-29	Home Oil	Pierson L. Amaranth-MC 3b A	1709	586	14.2	2.0	4 489.2	COOP
	4-15-1-24	Tundra Oil and Gas	Other Areas L. Amaranth I	2216	1237	4.8 (2 months)	4.5	179.4	COOP
		2nd leg	KOP-1011 m	1490	479				
Mission Canyon 3	5-30-1-28	Williston Wildcatters	Pierson - MC 3	1360	218	-	-	-	COMP
		2nd leg	KOP-1156 m	1397	241				
	5-3-2-26	NCE Petrofund	Waskada MC 3b B	1624	600	12.0	2.4	6 001.1	COOP
	12-5-3-28	Home Oil	Pierson MC 3b B	1494	415	7.0	SI	1 464.9	COOP
	1-26-1-26	NCE Petrofund	Waskada MC 3a A	1811	788	6.5	1.3	3 152.3	COOP
	14-34-1-26	NCE Petrofund	Waskada MC 3b B	1581	543	8.0	1.5	3 745.9	COOP
	10-35-1-26	NCE Petrofund	Waskada MC 3a I	1410	368	6.8	2.6	4 404.6	COOP
		2nd leg	KOP-1341 m	1587	246				
	3-18-3-28	Tundra Oil and Gas	Pierson MC 3b B	1877	791	25.8	13.1	19 634.2	COOP
	6-11-3-29	Tundra Oil and Gas	Pierson MC 3a C	1215	127	4.9	-	-	
		2nd leg	KOP-1094 m	1697	603				
		3rd leg**	KOP- 1215 m	1820	605	5.5	4.2	2 977.8	COOP
	A3-18-3-28	Tundra Oil and Gas	Pierson MC 3b B	1888	820	21.8	19.4	15 531.0	COOP
	11-17-3-28	Tundra Oil and Gas	Pierson MC 3a B	2003	945	15.5	12.9	7 838.4	COOP
	3-22-3-28	Todd Ballantyne	Pierson MC 3a B	1658	561	-	SI	57.6	COOP

*3rd leg on Production July 26, 1995, 1st & 2nd leg on Production June 28, 1993

**3rd leg on Production Sep. 20,1996, 1st & 2nd leg on Production Sep. 14, 1995

QUARTERLY MANITOBA HORIZONTAL WELL PRODUCTION SUMMARY

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m^3/d)	DAILY PRODUCTION Dec/97 (m^3/d)	CUMULATIVE PRODUCTION (m^3)	STATUS
Mission Canyon 3	11-6-3-29	Search Energy	Pierson MC 3b-MC 3a A	1605	440	25.2 (2 months)	22.2	1 283.5	COOP
	2nd leg	KOP-1170 m	1464	294					
	5-12-3-29	Tundra Oil and Gas	Pierson MC 3a C	1844	763	23.4 (1 month)	23.4	93.7	COOP
	5-6-3-29	Search Energy	Pierson	1537	402	-	-	-	COMP
		2nd leg	KOP-1154 m	1511	357				
Mission Canyon 1	1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1680	570	26.7	5.3	16 746.5	COOP
	A1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1724	691	26.8	26.3	31 286.7	COOP
	2-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1864	756	33.3	12.7	25 456.9	COOP
		2nd leg	KOP-1282 m	1657	375				
	3-31-5-29	HCO Energy	Tilston MC 1 A	1628	580	13.9	3.0	3 403.1	COOP
		2nd leg	KOP-1082 m	1584	502				
	6-8-6-28	HCO Energy	Other Areas - MC 1 E	1554	495	14.5	SI	5 964.1	COOP
	12-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1335	328	22.5	3.4	10 511.7	COOP
	12-32-5-29	HCO Energy	Tilston MC 1 A	1538	485	14.7	0.4	3 820.8	COOP
	11-6-6-28	HCO Energy	Other Areas - MC 1 E	1424	778	3.9	0.6	797.1	COOP
	A3-31-5-29	HCO Energy	Tilston MC 1 A	1463	412	5.4	0.6	1 088.9	COOP
	10-31-5-29	HCO Energy	Tilston MC 1 A	1763	697	8.3	0.9	2 271.7	COOP
	11-15-6-29	Tundra Oil and Gas	Tilston MC 1 C	1123	125	27.0	7.5	13 787.8	COOP
		2nd leg	KOP-1048 m	1378	330				
	B1-8-6-29	Tundra Oil and Gas	Tilston MC 1 C	1732	697	29.6	16.3	11 900.1	COOP
	12-9-6-29	Tundra Oil and Gas	Tilston MC 1 C	1284	289	36.4	11.2	11 163.9	COOP
		2nd leg	KOP-1052 m	1238	186				
		3rd leg	KOP-1137 m	1630	493				
	8-14-6-27	Sceptre Resources	Other Areas MC 1 H	1780	789	13.9	SI	3 586.2	COOP
	2-16-6-26	Sceptre Resources	Other Areas MC 1 G	1087	247	9.6	SI	2 557.0	COOP
		2nd leg	KOP-960 m	1229	269				
	6-14-6-27	CanNat Resources	Other Areas MC 1 H	1649	738	13.0	SI	1 778.0	COOP
	14-9-6-26	Rigel Oil & Gas	Other Areas MC 1 G	1355	463	38.7	11.4	5 691.4	COOP
	15-16-6-26	CanNat Resources	Other Areas MC 1 G	1700	837	11.7	SI	1 534.3	COOP
	3-9-6-26	Rigel Oil & Gas	Other Areas	1390	332	-	-	-	COMP
	RE13-4-6-26	Rigel Oil & Gas	Other Areas	1293	394	-	-	-	WOSR
	A14-9-6-26	Rigel Oil & Gas	Other Areas MC1 G	1270	395	0.7 (4 months)	0.4	62.2	COOP
	4-16-6-26	CanNat Resources	Other Areas MC 1 G	1299	459	12.9 (4 months)	SI	1 042.2	COOP
	11-9-6-26	Rigel Oil & Gas	Other Areas	1248	224	-	-	-	COMP

QUARTERLY MANITOBA HORIZONTAL WELL PRODUCTION SUMMARY

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m³/d)	DAILY PRODUCTION Dec/97 (m³/d)	CUMULATIVE PRODUCTION (m³)	STATUS
Lodgepole	8-30-10-28	Tundra Oil and Gas	Daly Lodgepole E	1220	331	5.4	3.4	8 762.9	COOP
	5-18-12-29	Neutrino Resources	Kirkella Lodgepole Daly C	885	104	2.7	-	651.5	SWD
	6-17-12-29	Neutrino Resources	Kirkella Lodgepole Daly B	1219	455	3.0	-	515.2	SWD
	5-17-12-29	Neutrino Resources	Kirkella Lodgepole Daly B	1320	523	3.3	0.3	930.2	COOP
	7-22-9-29	Rideau Petroleums	Daly Lodgepole D	1338	472	2.1	0.4	1 372.7	COOP
	14-22-8-28	Herc Oil	Daly Lodgepole O	1584	621	1.4	SI	461.6	COOP
		2nd leg	KOP-874 m	1366	492				
	3-17-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1543	816	10.3	11.6	15 822.4	COOP
	15-17-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1359	612	4.8	2.2	4 107.7	COOP
	6-33-8-28	Herc Oil	Daly Lodgepole Q	1197	321	2.6	SI	83.1	COOP
	14-16-6-22	Tundra Oil and Gas	Souris Hartney Lodgepole Virden A	1386	634	7.4	7.6	5 769.2	COOP
	3-20-11-26	Upton Resources	Virden Lodgepole A	1271	499	4.7	4.6	2 074.4	COOP
	6-26-11-26	Chevron Canada	Virden Lodgepole A	1135	461	-	-	-	J&A
		2nd leg	KOP-677 m	1102	425	5.2	4.4	1 868.6	COOP
	7-33-11-26	Chevron Canada	Virden Lodgepole A	1118	390	27.7	26.7	13 626.0	COOP
	12-34-11-26	Chevron Canada	Virden Lodgepole A	1138	411	11.2	5.3	3 674.1	COOP
	13-29-10-28	Tundra Oil and Gas	Daly Lodgepole E	1390	542	15.4	12.4	6 809.7	COOP
		2nd leg	KOP-873 m	1520	647				
	4-11-10-28	Chevron Canada	Daly Lodgepole A	1555	678	3.4	7.4	1 830.7	COOP
	15-2-10-28	Chevron Canada	Daly Lodgepole A	1551	667	7.4	5.9	2 970.3	COOP
	13-15-11-26	Chevron Canada	Virden Lodgepole A	1383	623	9.1	7.1	3 014.4	COOP
	11-16-2-21	Enron Oil	Other Areas Lodgepole WL E	1451	373	17.6	12.4	3 025.7	COOP
	4-2-3-21	Enron Oil	Whitewater Lodgepole WL B	1440	553	4.5	3.8	698.8	COOP
	1-20-9-25	Chevron Canada	Virden Lodgepole C	1207	540	9.4 (5 months)	7.4	1 171.4	COOP
	3-12-10-28	Chevron Canada	Daly Lodgepole A	1155	400	2.2 (3 months)	1.7	170.1	COOP
	15-12-10-28	Chevron Canada	Daly Lodgepole A	1159	409	6.5 (5 months)	15.0	791.1	COOP
	1-31-9-28	Chevron Canada	Daly Lodgepole A	1238	428	3.1 (3 months)	1.9	283.8	COOP
	16-30-11-26	Mountcliff Resources	Virden Lodgepole A	1465	755	-	-	-	COMP
		2nd leg	KOP-755 m	1131	376				
	12-26-1-21	Tundra Oil and Gas	Lulu Lake Lodgepole WL B	1912	806	-	-	-	COMP
		2nd leg	KOP-1425 m	1903	478				
	3-4-12-26	Chevron Canada	Virden Lodgepole A	1156	534	7.7 (3 months)	4.8	690.1	COOP

QUARTERLY MANITOBA HORIZONTAL WELL PRODUCTION SUMMARY

PRODUCING FORMATION	WELL	LICENSEE	PRODUCING POOL	MD (m)	HORIZONTAL SECTION LENGTH (m)	INITIAL PRODUCTIVITY 1ST 6 MONTHS OR LESS (m^3/d)	DAILY PRODUCTION Dec/97 (m^3/d)	CUMULATIVE PRODUCTION (m^3)	STATUS
Lodgepole	15-6-11-25	Chevron Canada	Virden Lodgepole B	1095	505	1.9 (3 months)	2.0	131.2	COOP
	15-22-11-26	Chevron Canada	Virden Lodgepole A	1303	671	7.6 (3 months)	7.5	571.6	COOP
	10-25-10-26	Chevron Canada	Virden Lodgepole B	1275	660	30.6 (3 months)	25.1	2 113.6	COOP
	12-13-10-28	Chevron Canada	Daly Lodgepole A	1417	644	7.3 (2 months)	6.1	392.3	COOP
	5-30-10-28	Tundra Oil and Gas	Daly	1905	1103	-	-	-	COMP
	6-33-10-29	Tundra Oil and Gas	Daly	1770	851	-	-	-	COMP
	4-29-11-26	Tundra Oil and Gas	Virden	1323	583	-	-	-	WOSR
		2nd leg	KOP-792 m	1689	897				
Confidential	5-32-5-26	Rigel Oil & Gas	Confidential	1073	---	-	-	-	COMP
	A11-9-6-26	Rigel Oil & Gas	Confidential	1370 (Proj.)	---	-	-	-	LOC
	14-22-6-26	CanNat Resources	Confidential	800 (Proj.)	---	-	-	-	LOC
	15-29-9-25	Tundra Oil and Gas	Confidential	1320 (Proj.)	---	-	-	-	LOC

B

Montana Horizontal Drilling Update

Larry N. Smith
Montana Bureau Of Mines and Geology

MONTANA HORIZONTAL DRILLING UPDATE

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Horizontal drilling for oil in Montana has increased dramatically since 1992 due to continued successful drilling along the Cedar Creek Anticline (CCA) and favorable tax legislation enacted by the Montana State Legislature (Figure 1). Horizontal drilling began in Montana in 1988 with Meridian Oil's use of the technology in a Red River Formation pilot waterflood project in East Lookout Butte field on the Cedar Creek Anticline.

The national upswing in activity was reflected in a significant increase in all drilling and permitting last year in Montana; drilling increased by nearly 33% between 1996 and 1997. Of the 77 wells completed since 1996, about 45% were in the Red River, 10% were in the Silurian/Ordovician interval along the CCA, 9% were in the Ratcliffe, 3% were in other Madison Group reservoirs, 6% were in the Charles 'C,' and 4% in the Nisku/Duperow interval (Figure 2). As of March 1998, 213 horizontal wells have been completed or have been spudded, of which 148 were originally completed as producers; an additional 47 permits are active (Figure 3). Activity in the state has been dominated by Burlington Resources' and Shell Exploration and Production's development of Red River Formation and Silurian/Ordovician reservoirs in and near established fields along the Cedar Creek Anticline. However, in the past year other companies, including Continental Resources, Samedan, and Wascana (Figure 4), have become significant players through westward extension of Red River and other development into Montana (Figures 2 and 4).

Cumulative production from all horizontal wells has totaled about six million barrels of oil (MMBO), with only partial reports thus far for 1997 production. Only three wells have produced more than 0.14 MMBO; however, the production history of most wells is less than three years (Figure 5). Although only about 19% of Montana's Williston Basin oil was produced from horizontal wells, production from these wells has reversed the historic decline in production from this province (Figure 6), which accounts for 78% of production in the state. The Red River, Silurian-Ordovician, and Madison Group units account for 87% of production to date from horizontal wells (Figure 7).

RED RIVER FORMATION AND SILURIAN/ORDOVICIAN RESERVOIRS

The most extensive history for horizontal wells is that of Burlington Resources' development of Red River Formation dolomites in East Lookout Butte field and surrounding area on the northeast flank of the Cedar Creek Anticline. Burlington Resources has spudded or completed 15 wells since 1996 and has another six active permits in the area. Horizontal wells completed to date are being used as injectors (14) and producers (32) in a waterflood of the field. Most of the horizontal legs are being oriented perpendicular to the strike of the fold limb, parallel to the maximum horizontal compressive stress direction. The tax rates, as amended for enhanced recovery projects and horizontal completions, have benefitted the economics of this venture.

Production in Burlington Resources's East Lookout Butte area is on a downdip leg of the crestal Lookout Butte field operated by Shell. Over the years, Shell has completed 15 horizontal wells (including one Madison producer) in its Lookout Butte holdings; they have no active permits in that area. Shell has spudded or completed 48 additional Red River or Silurian/Ordovician wells in the Pennel, Cabin Creek, Little Beaver, Monarch, South Wills Creek, and Pine Canyon fields. Shell's lack of permitting activity suggests it has recently become inactive in further development activities in the state.

Extension of success from North Dakota into Montana by Continental Resources has occurred in the CCA area. Continental has completed eight wells and has seven active permits there. A handful of other operators completed one well each in the interval since 1996 (Figure 2);

Samedan has one permit for drilling the Red River.

MADISON GROUP

The Madison Group has received the greatest interest in horizontal drilling, except for the Red River/Silurian-Ordovician interval, because of the nature and importance of the reservoir in the state. Five wells were completed since 1996 in the Madison; there are no active permits (Figure 2). The Ratcliffe interval was the target of seven wells completed or spudded since 1996; all have had disappointing results so far.

OTHER RESERVOIRS

Nine wells were completed or spudded in the Nisku/Duperow interval since 1996 by Wascana, Samedan, and Hallwood; one permit is active for the zone. Other horizons were targeted in one or two additional wells (Figure 2); three permits are still active.

ACKNOWLEDGMENTS

Jim Halvorson of Montana's Oil and Gas Conservation Division (406-656-0040) contributed greatly to this paper. The Montana Bureau of Mines and Geology supported this paper and presentation.

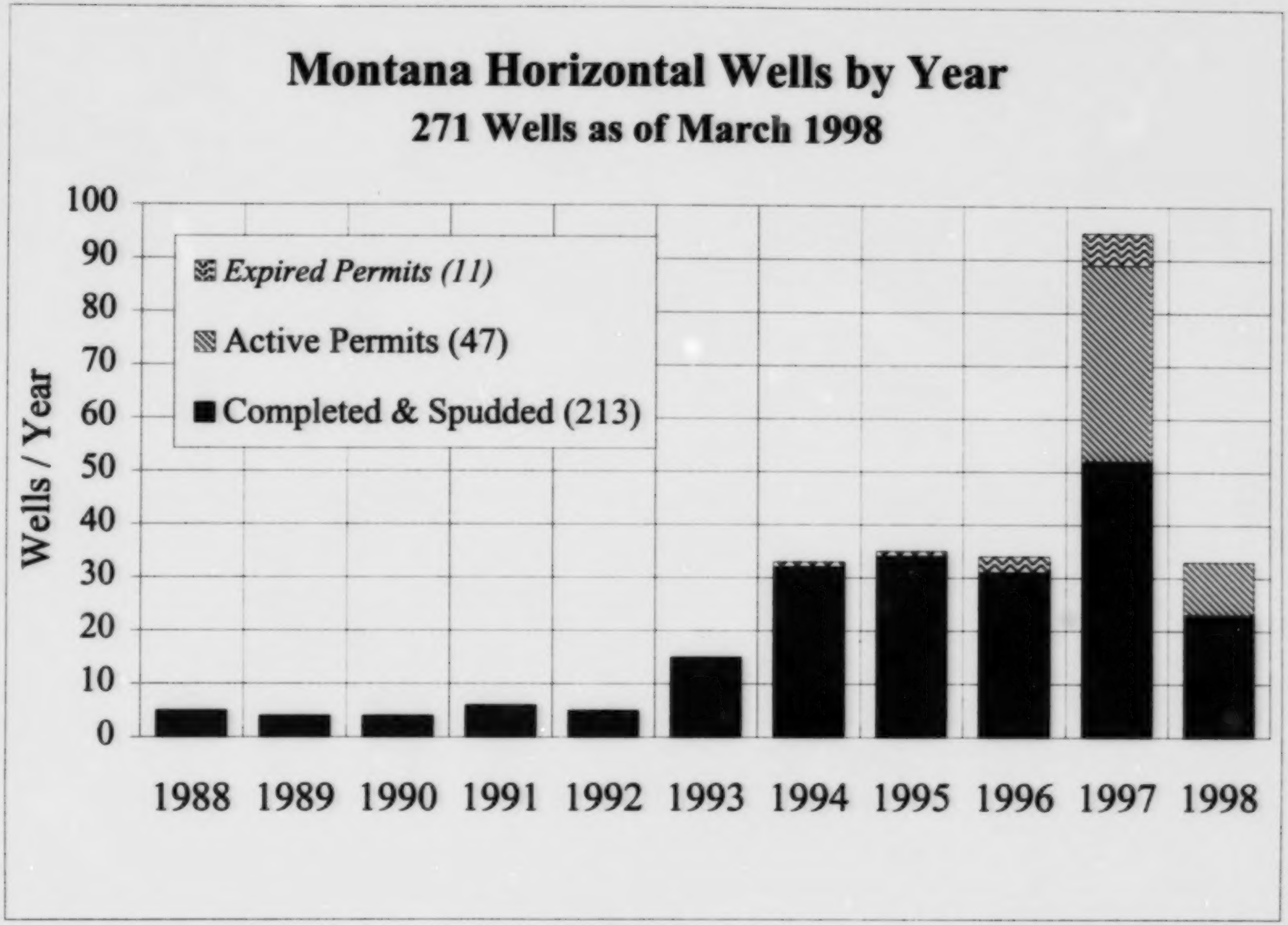

FIGURE 1 - Drilling and permitting history in Montana. LN Smith - MBMG Hz_stats 4/1/98

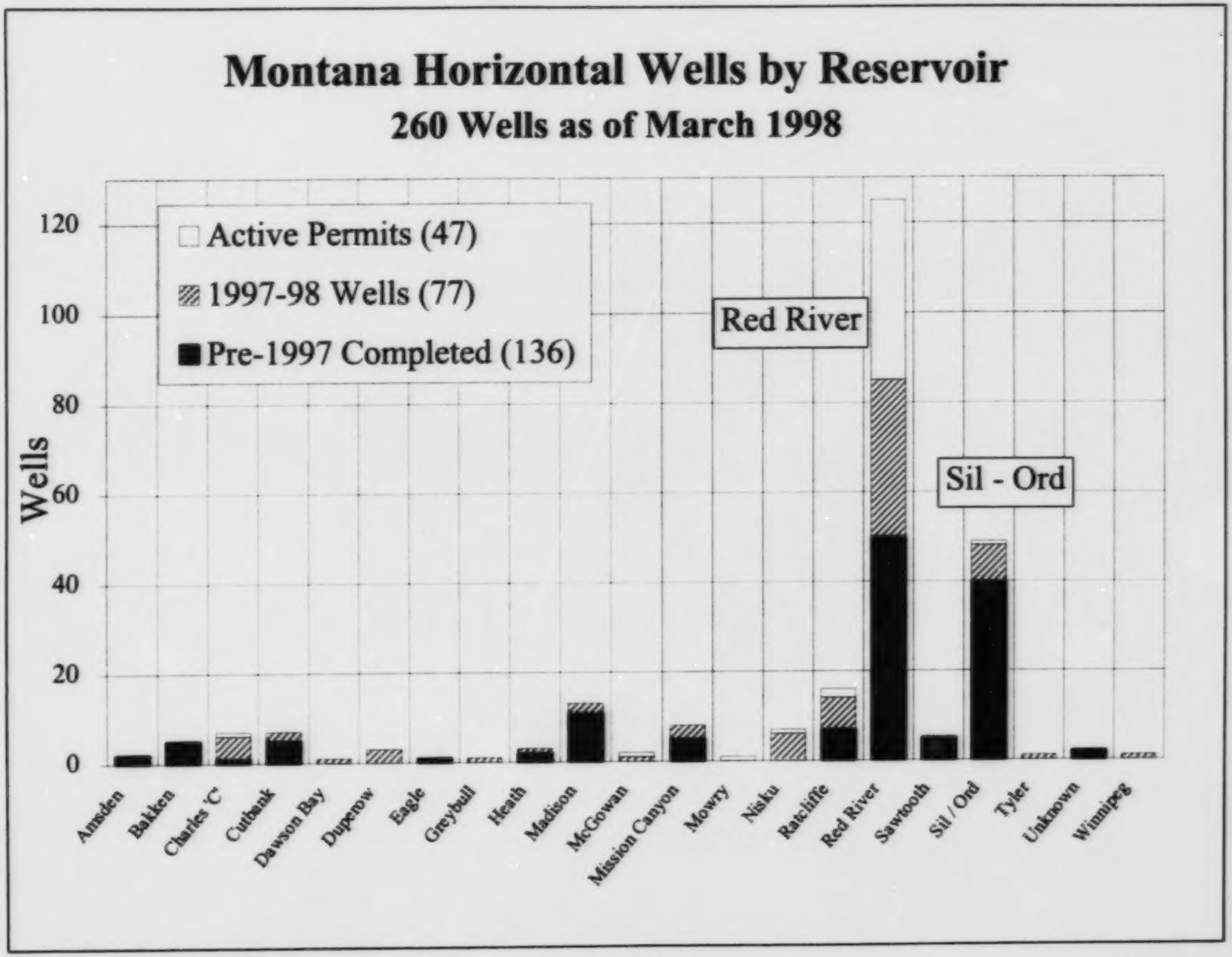

FIGURE 2 - Drilling and permitting by reservoir in Montana. LN Smith - MBMG Hz_stats 4/2/98

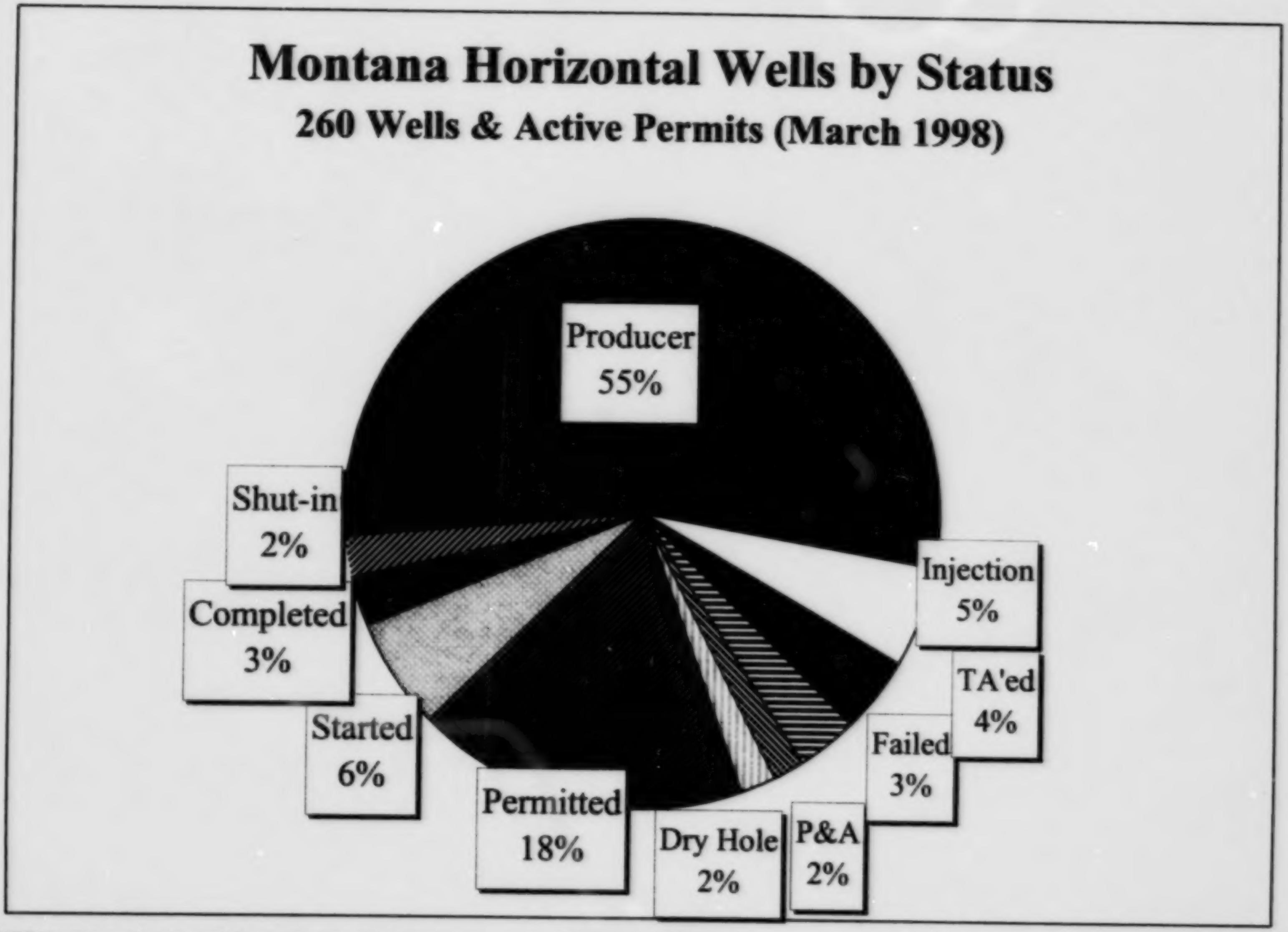

FIGURE 3 - Current status of Montana horizontal wells. LN Smith - MBMG Hz_stats 4/1/98

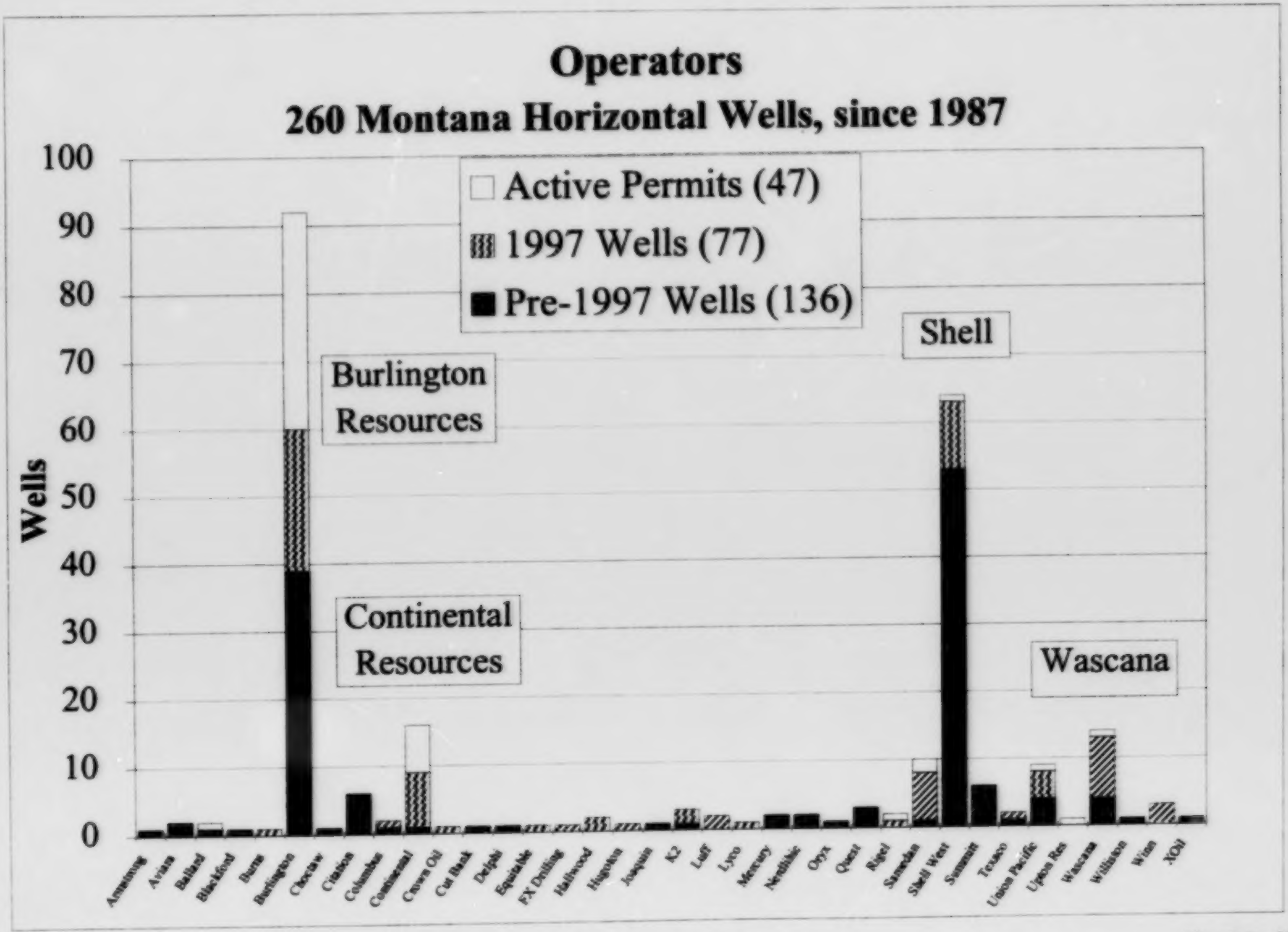

FIGURE 4 - Drilling and permitting by operator in Montana.

LN Smith - MBMG

Hz_stats 4/2/98

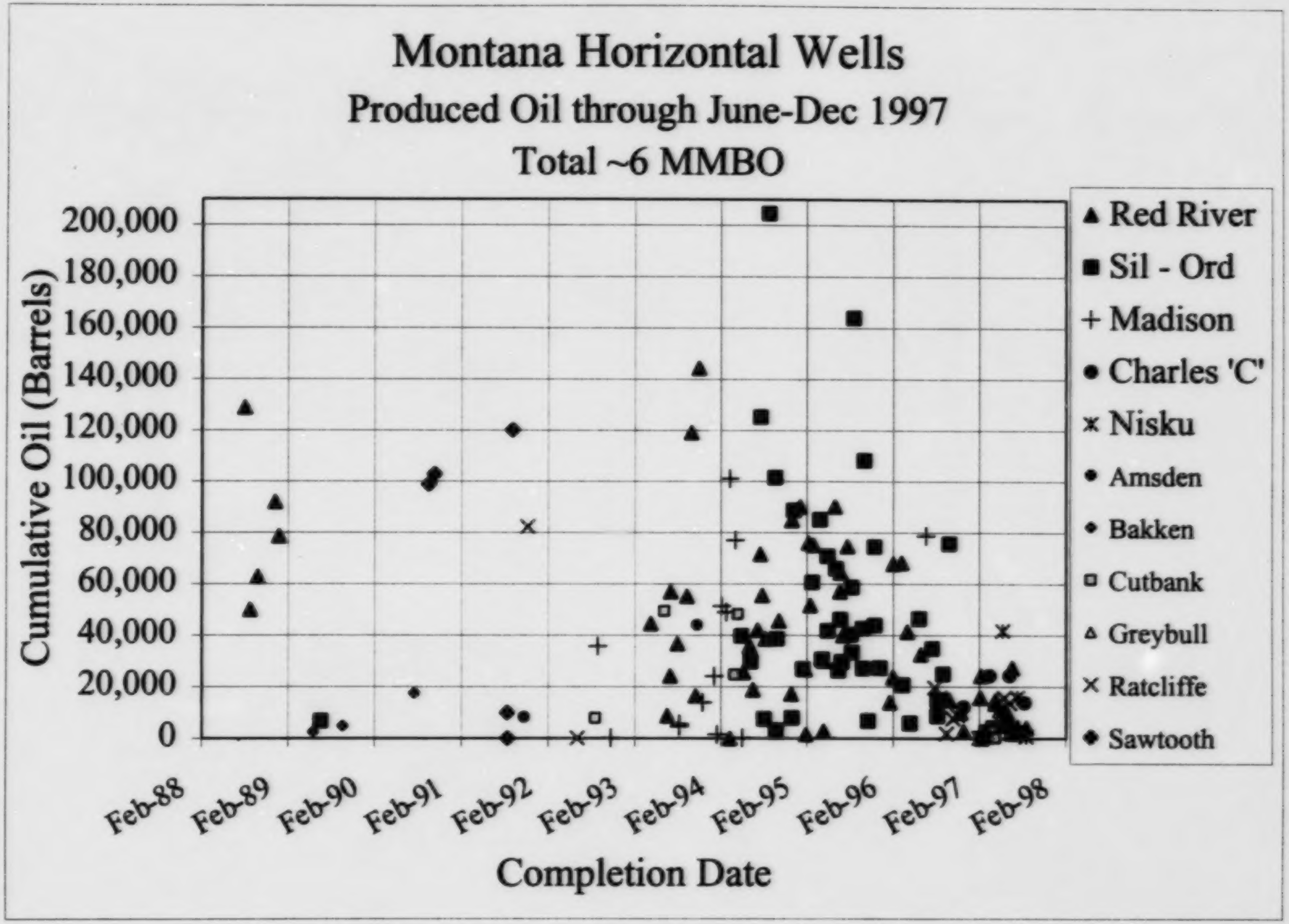

FIGURE 5 - Cumulative production versus completion date. LN Smith - MBMG Hz_stats 3/31/98

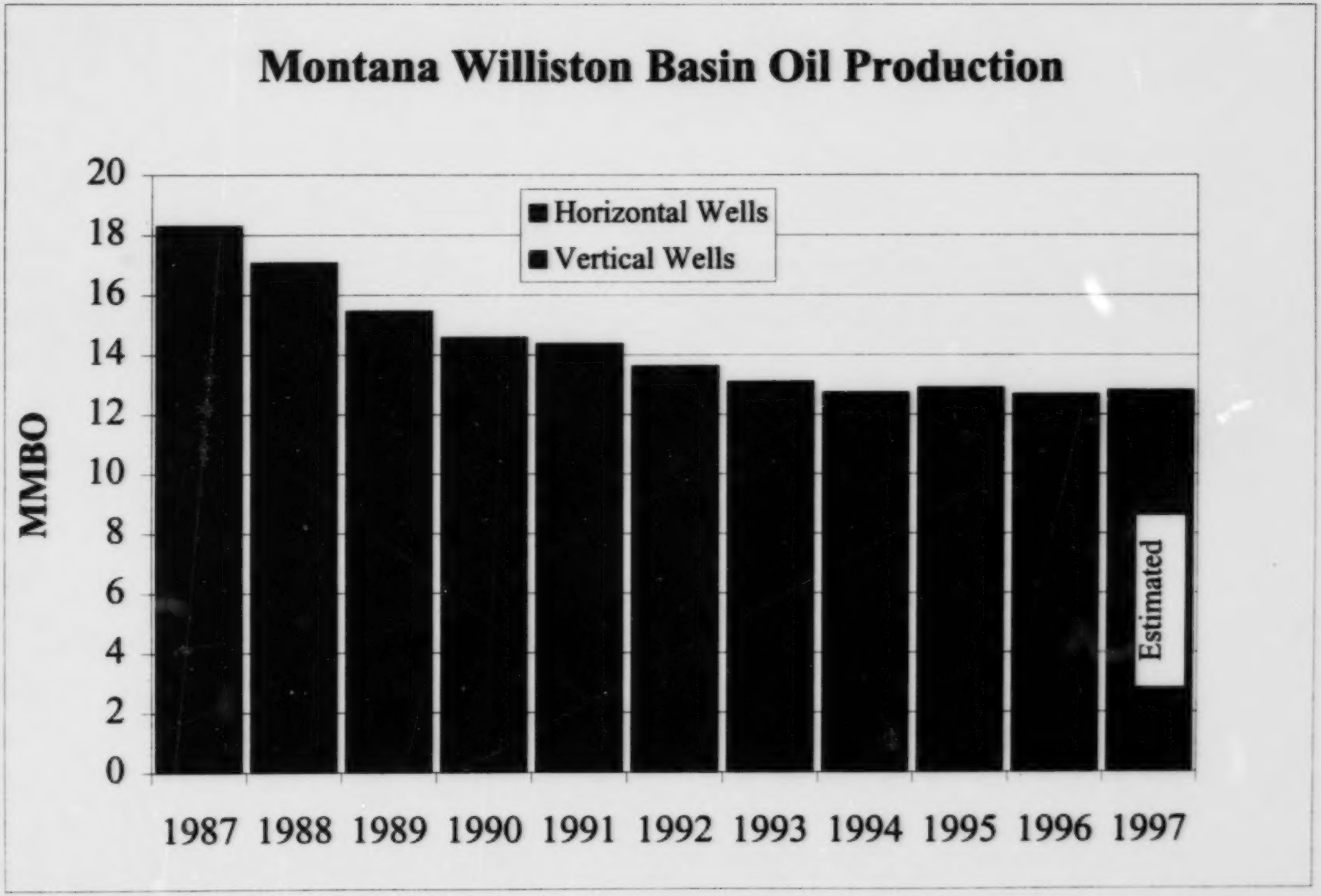

FIGURE 6 - Oil production in Montana portion of Williston Basin. LN Smith - MBMG

Hz_stats 3/31/98

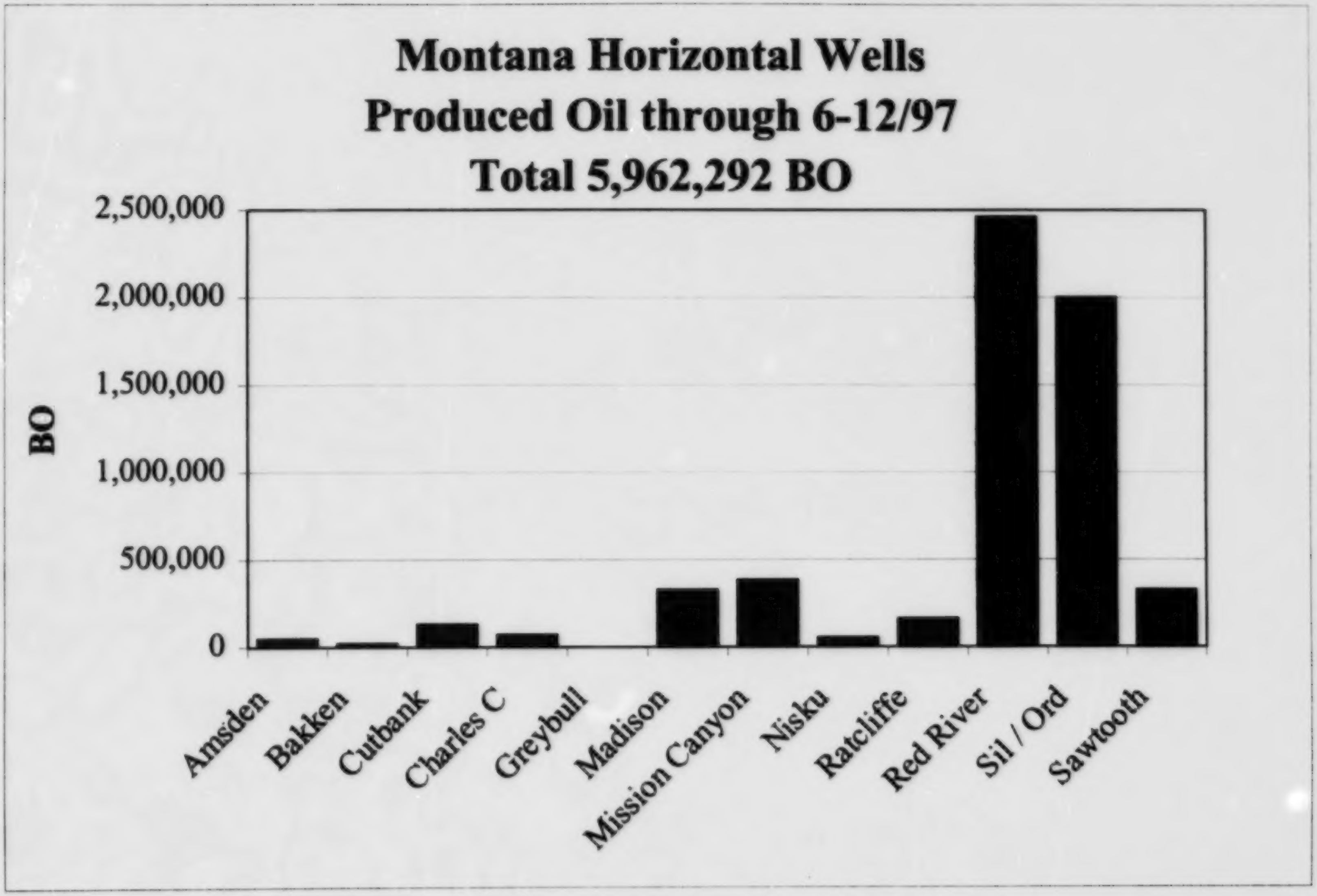

FIGURE 7 - Production by field. LN Smith - MBMG Hz_stats 3/31/98

C

North Dakota Horizontal Drilling Update

Bruce E. Hicks
North Dakota Industrial Commission
Oil & Gas Division

NORTH DAKOTA HORIZONTAL UPDATE

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Horizontal activity was at record levels in North Dakota during 1997. Monthly horizontal production rates continued to explode throughout most of the year, as operators continued their horizontal drilling programs in the **Madison** and **Red River** Formations. Production from horizontal wells continued to increase throughout the year and by year-end, averaged approximately 25,500 bopd (3980 cmopd), accounting for 25% of North Dakota's production, although only 12% of the producing wells are horizontal.

The horizontal rig activity remained extremely high throughout 1997. We had a record 17 rigs on horizontal wells in October and averaged 12.5 rigs for the year. The rig count will probably drop during 1998 due to the depressed oil price, although very interesting plays are continuing to be pursued in the State. A total of 110 horizontal wells were drilled during the year and 105 were completed as producers for a success rate of 95%. It appears that the level of activity in 1998 might approach that generated in 1997.

We had 121 horizontal permits issued in 1997. The **Madison** Formation accounted for 63 permits and the **Red River** Formation accounted for 54 permits. Numerous renewals were issued throughout the year, mainly for **Red River** wells to be drilled in Slope and Bowman Counties.

A total of 74 wells were drilled to the **Red River** Formation in North Dakota during 1997, of which, 70 wells were completed as producers for a success ratio of 95%. Ten wells were drilled in Slope County, 63 were drilled in Bowman County and 1 was drilled in Williams County. Production from Bowman County wells is from a depth of approximately 9100 feet (2770 meters), whereas Williams County production is approximately 2000 feet (610 meters) deeper. The average **Red River** horizontal well takes 35 days from spud to total depth and has an open hole lateral section of 4850 feet (1475 meters). The initial production from the wells averaged 267 bopd (42 cmopd). The **Red River** Formation currently accounts for 74% of North Dakota's horizontal production. The play should have continuing success in 1998, although with approximately 200 wells drilled to date, only the less desirable locations remain.

A total of 34 wells were drilled to the **Madison** Formation throughout North Dakota, of which, 33 wells were completed as producers for a success ratio of 97%. The **Madison** Formation currently accounts for 18% of North Dakota's horizontal production. Operators on the eastern flank of the Williston Basin drilled ten wells in the **Madison** Formation, all of which were producers. Production is shallow, coming from a depth of approximately 4000 feet (1220 meters). The average **Madison** Formation horizontal well in this area takes 14 days from spud to total depth and has a lateral section of 2120 feet (645 meters). The initial production from the wells averaged 154 bopd (25 cmopd). Twenty-four additional wells were drilled in the **Madison** Formation throughout North Dakota in Billings, Burke, Dunn, McKenzie, McLean, Mountrail and Williams Counties. The average well in this area takes 35 days from spud to total depth and has a lateral section of 2650 feet (800 meters). The initial production from these wells averaged 150 bopd (24 cmopd).

The **Bakken** Formation accounts for 56% of the cumulative horizontal production, although it only accounts for 8% of present horizontal production. The **Bakken** Formation had very little horizontal activity in 1997. Only two wells were drilled during the year and production from the 152 wells at year-end averaged 13 bopd (2 cmopd). The wells are still economic since the average water cut is only 6%, a premium oil price is paid for the sweet crude, and the current production decline is minimal.

The five most active counties in 1997 (vertical + horizontal) were Bowman, Bottineau, Slope, Williams and Stark Counties. Bowman County had 54 wells completed as producers, almost all of which were from horizontal wells drilled in the **Red River** 'B' Pool. Production increased 15% during 1997, keeping Bowman our number one producing county for the year. Bottineau County had 16 wells completed as producers, half of which were horizontal wells drilled in the Madison Formation. Although no increase occurred, production stabilized during the year and it appears continuing interest in the county during 1998 will reflect another good year. Slope County had 10 wells completed as producers, all of which were from horizontal wells drilled in the **Red River** 'B' Pool. Production in the county increased to 1880 bopd (300 cmopd) by year-end and producing wells went from 4 to 13, resulting in a dramatic increase in oil production. Stark County had the most significant production increase in North Dakota, even though only 7 wells were completed as producers, none of which were horizontal wells. The increase was almost entirely due to the enhanced recovery operations implemented in the Eland-**Lodgepole** Unit, which produced approximately 12,000 bopd during the last half of the year!

The year 1998 will be very interesting for North Dakota. Depressed oil prices may significantly affect future horizontal plays in the State, although several **Madison** plays continue to show interest and a portion of the **Red River** 'B' Pool may be unitized before year-end.

North Dakota oil production is assessed a **gross production tax** and an **oil extraction tax**. All existing wells and new wells drilled are assessed the 5% gross production tax. The oil extraction tax is 4% for all wells drilled after April 27, 1987 and 6.5% for all wells drilled prior to April 27, 1987. The North Dakota Legislature has passed numerous exemptions to the oil extraction tax. The following waivers on the oil extraction tax can be obtained:

---All production from a stripper well property.
---10 years following production from a two-year inactive well.
---10 years following the date incremental production commences from a tertiary recovery project.
---5 years following the date incremental production commences from a secondary recovery project.
---The first 24 months of production for all new horizontal wells.
---The first 15 months of production for new vertical wells.
---The 12 months following a qualifying workover project.

---9 months following production from a horizontal reentry well.
---The first 60 months of production for all wells located within the boundary of an Indian Reservation.

FOR FURTHER INFORMATION CONTACT:

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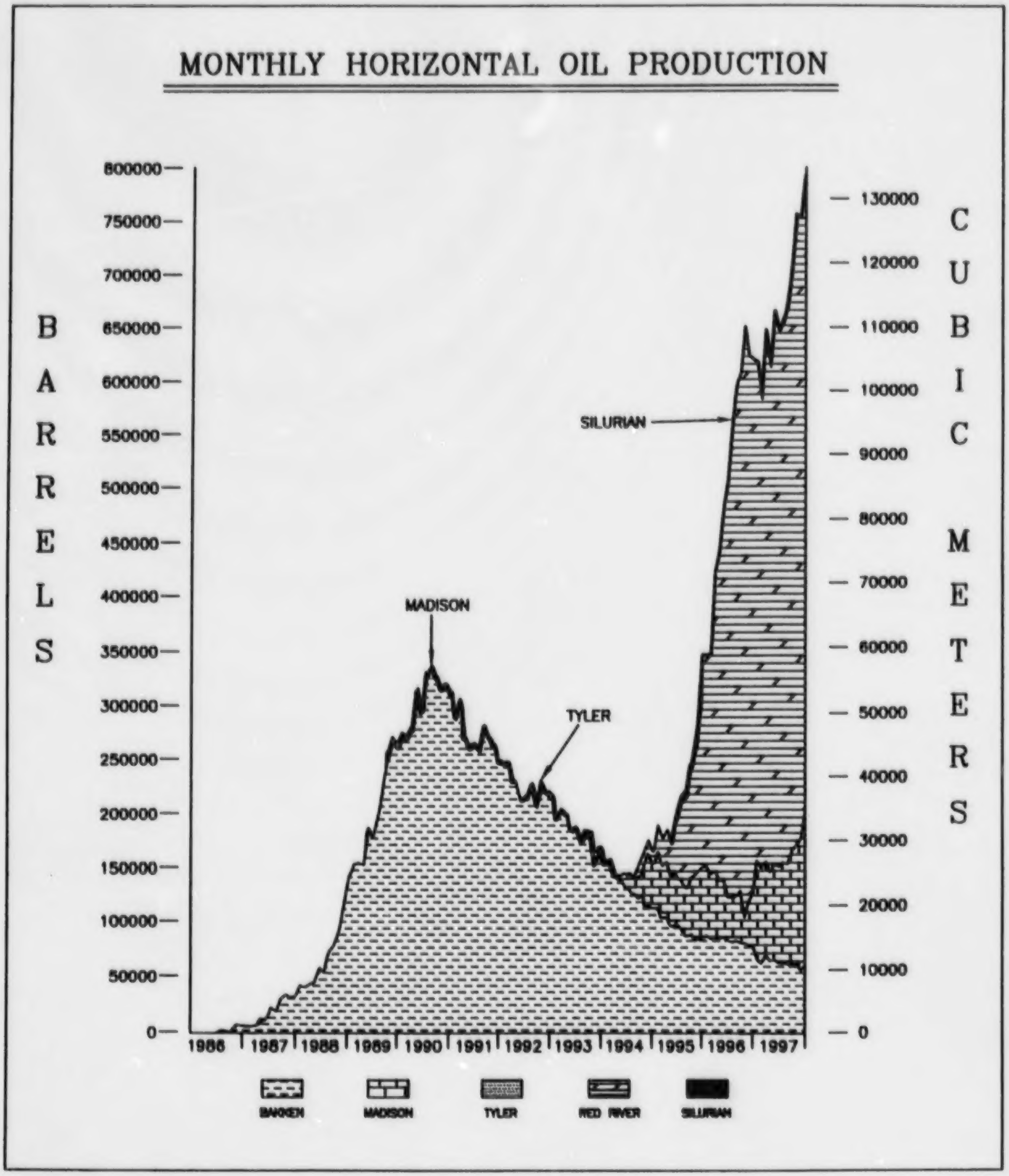
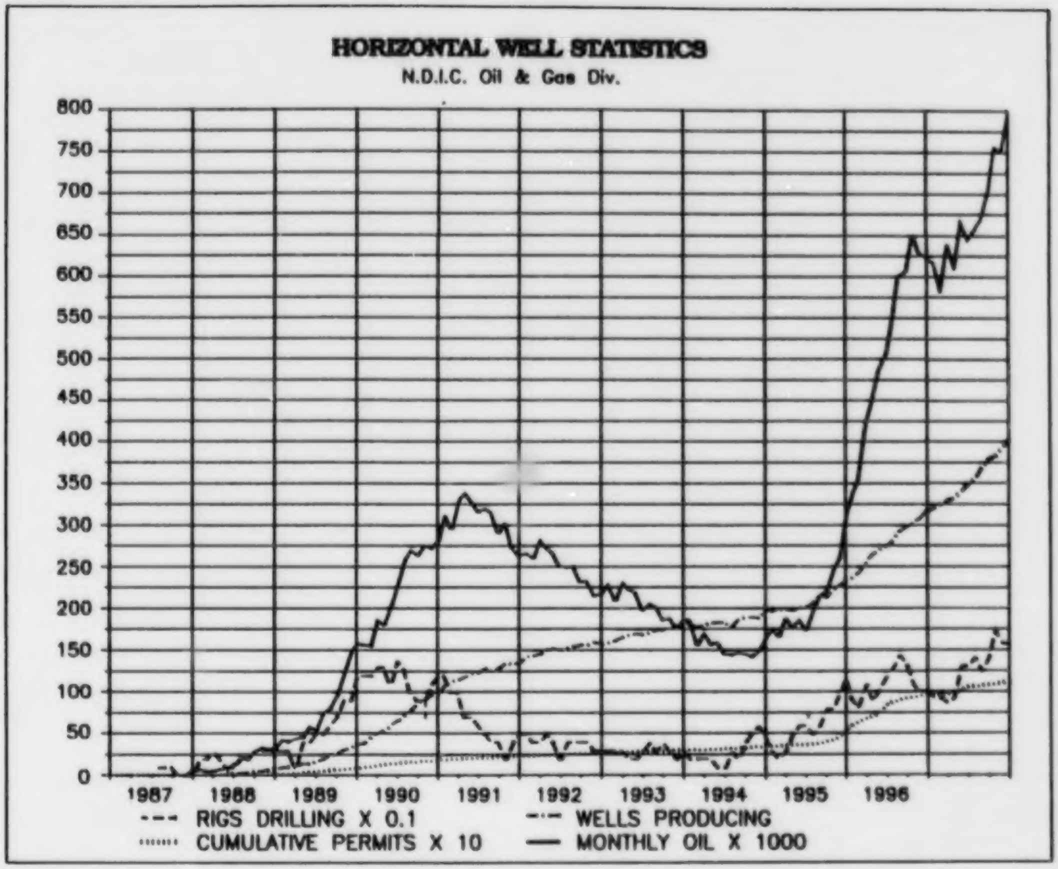
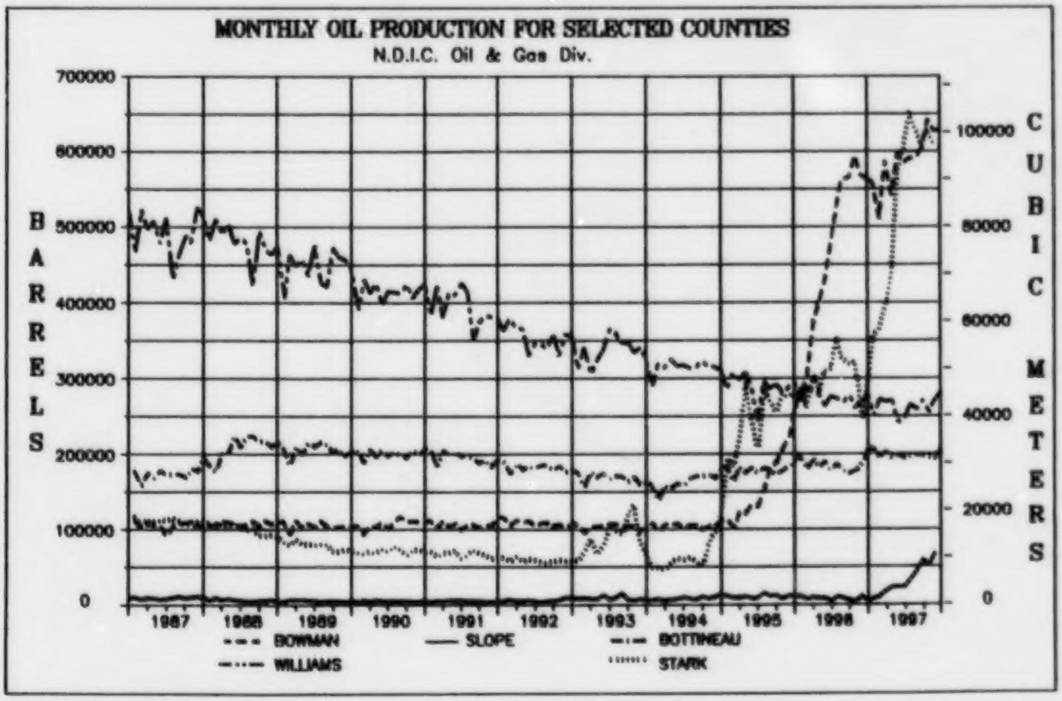
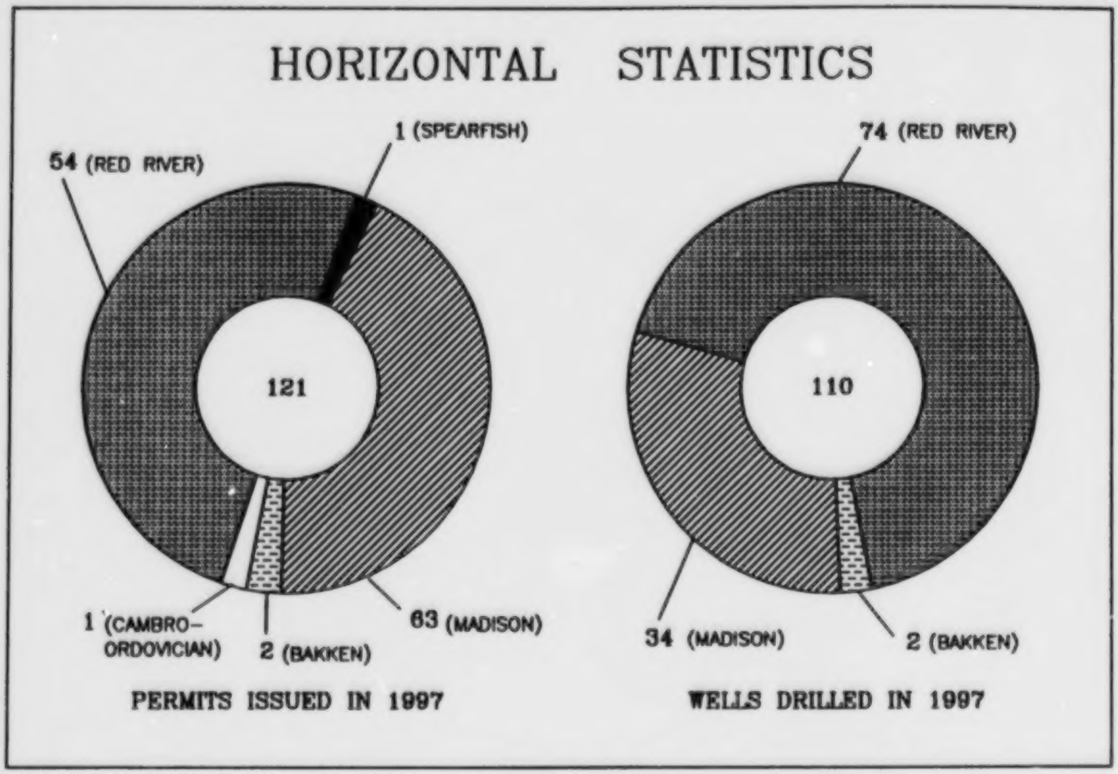

MONTHLY HORIZONTAL OIL PRODUCTION
BARRELS
CUBIC METERS
800000
750000
700000
650000
600000
550000
500000
450000
400000
350000
300000
250000
200000
150000
100000
50000
0
130000
120000
110000
100000
90000
80000
70000
60000
50000
40000
30000
20000
10000
0
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
MADISON
TYLER
SILURIAN
BAKKEN
MADISON
TYLER
RED RIVER
SILURIAN

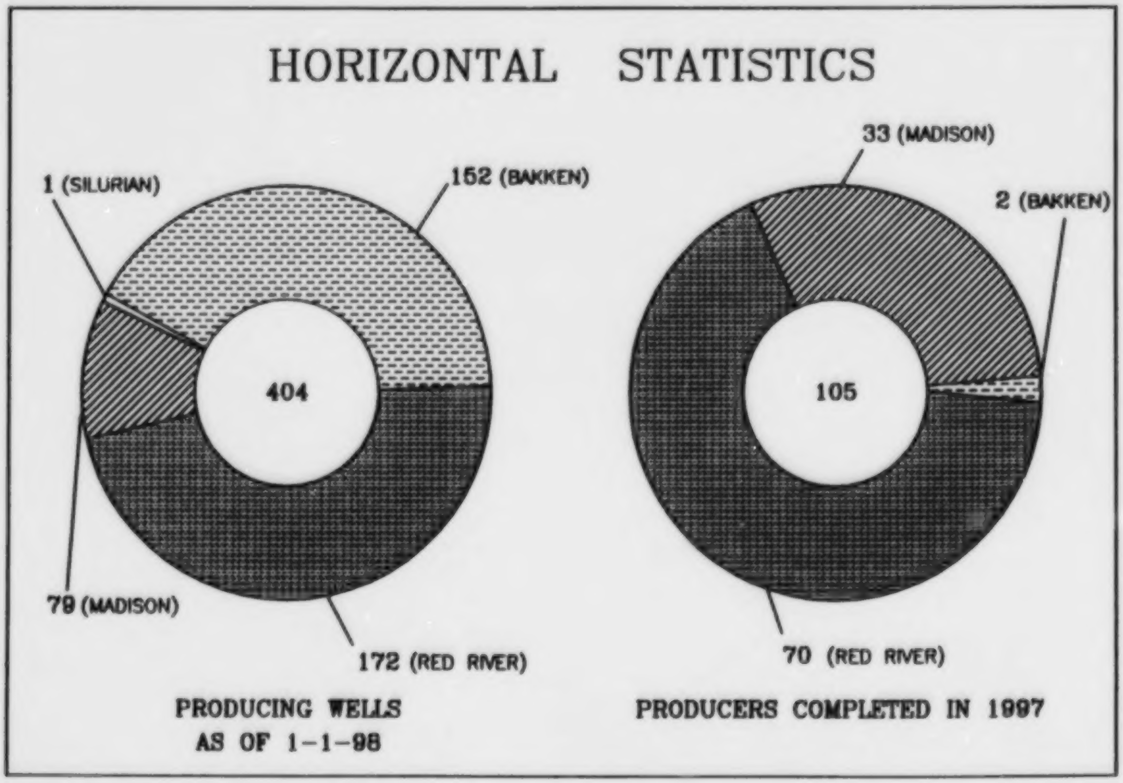

HORIZONTAL WELL STATISTICS
N.D.I.C. Oil & Gas Div.
800
750
700
650
600
550
500
450
400
350
300
250
200
150
100
50
0
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
RIGS DRILLING X 0.1
WELLS PRODUCING
CUMULATIVE PERMITS X 10
MONTHLY OIL X 1000


MONTHLY OIL PRODUCTION FOR SELECTED COUNTIES
N.D.I.C. Oil & Gas Div.
BARRELS
700000
600000
500000
400000
300000
200000
100000
0
CUBIC METERS
100000
80000
60000
40000
20000
0
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
BOWMAN
SLOPE
BOTTINEAU
WILLIAMS
STARK



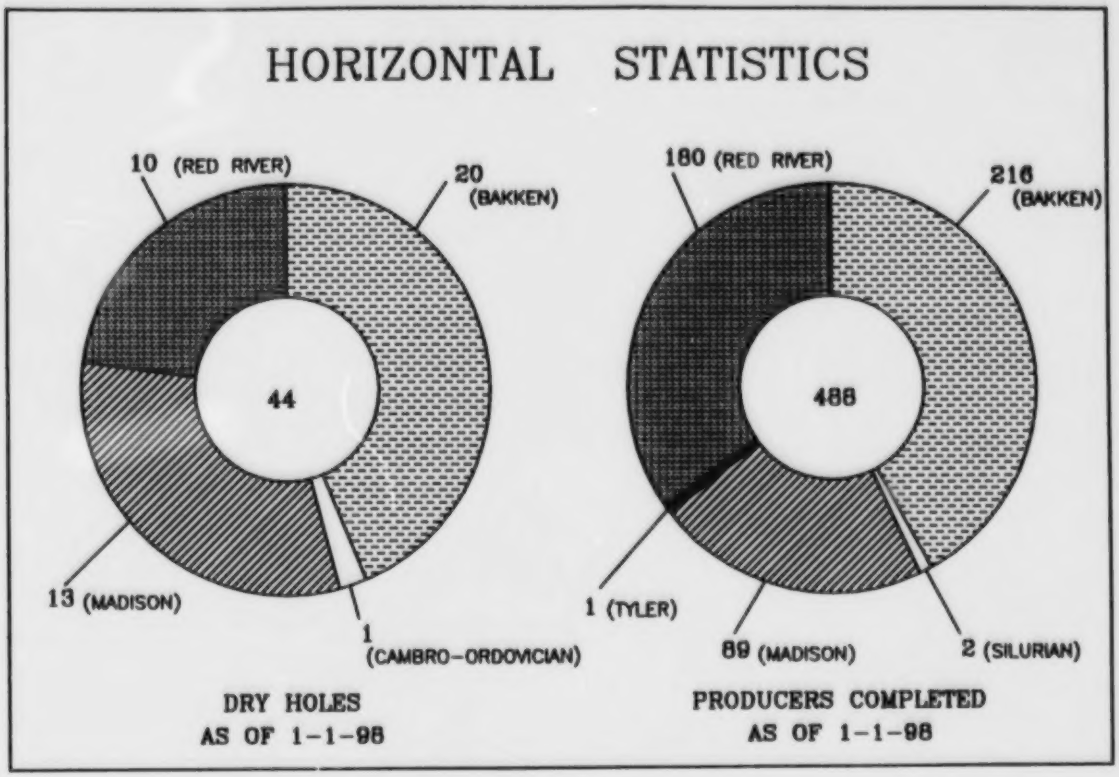
PERMITS ISSUED IN 1997

WELLS DRILLED IN 1997



PRODUCING WELLS
AS OF 1-1-98

PRODUCERS COMPLETED IN 1997


HORIZONTAL STATISTICS
10 (RED RIVER)
20 (BAKKEN)
44
13 (MADISON)
1 (CAMBRO-ORDOVICIAN)
DRY HOLES AS OF 1-1-98
180 (RED RIVER)
216 (BAKKEN)
488
1 (TYLER)
89 (MADISON)
2 (SILURIAN)
PRODUCERS COMPLETED AS OF 1-1-98

D

South Dakota Horizontal Drilling Update

Gerald (Mack) McGillivray
South Dakota Department of Environment and
Natural Resources Oil & Gas Program

SOUTH DAKOTA HORIZONTAL DRILLING UPDATE

Gerald (Mack) McGillivray
South Dakota Department of Environment and Natural Resources
Oil & Gas Program

In many respects, horizontal drilling is relatively new to South Dakota, with most of the horizontal drilling activity having occurred since 1994. The exception is one well drilled in 1988. From 1994 to 1996 horizontal drilling was on the rise, with two wells drilled in 94, three in 95, and seven in 96. In 1997 however, drilling activity fell to five wells (Figure 1).

Since 1988, 16 new horizontal wells have been drilled, and 2 existing vertical wells have been re-entered and horizontally drilled. Of those 18 wells, 9 are currently producing; 4 are currently injecting (2 injecting water as part of a water flood project, 2 are injecting air as part of a "fire flood" project); 2 have been temporarily abandoned; and 3 have been plugged and abandoned (Figure 2).

All of the horizontal wells have been drilled in Harding County, and have targeted the Ordovician Red River Formation, primarily the "B" Porosity Zone (Figure 3). The lengths of the lateral sections range from 904 feet to 5109 feet (Figure 4).

To date, the operators conducting horizontal drilling projects and the number of wells they drilled are; Continental Resources (8), Citation Oil & Gas (4), Merit Energy (2), Burlington Resources (1), Luff Exploration (1), Summit Resources (1), and Samedan (1) (Figure 5). Other operators that have established horizontal spacing but have not commenced drilling horizontal wells are Wyoming Resources, Sage Energy, and Kep Energy.

Prior to 1997, oil production from horizontal wells had not contributed significantly to South Dakota's overall crude oil production. Beginning in 1994, one horizontal well produced 4211 barrels, only .2% of the total crude oil output for the state, 1,453,139 barrels. In 1995, two horizontal wells produced 27,422 barrels, about 2% of the state total of 1,352,436 barrels. In 1996, six horizontal wells produced 44,164 barrels, about 3.5% of the state total of 1,257,476 barrels. In 1997 however, eleven horizontal wells (two wells were converted to injection midway in the year) contributed 126,925 barrels, about 9.5% of the state total of 1,334,041 barrels. 1997 also ended a five year decline in total crude oil production, which is largely due to the output of the horizontal wells (Figures 6a & 6b).

A closer look at 1997 production figures shows monthly oil production from horizontal wells increased dramatically during the course of the year. In January the horizontal wells produced 4423 barrels, about 4% of the state total of 104,123 barrels. In December the horizontal wells produced 18,483 barrels, about 16% of the state total of 113,589 barrels (Figures 7a, 7b, & 7c).

Although horizontal drilling in South Dakota decreased in 1997 from 1996 levels, hopefully drilling will increase in the near future. One indication of this anticipated increase in horizontal drilling activity is the increase in leasing and spacing activity in Harding County. Currently, over 90,000 acres has been spaced for horizontal drilling in Harding County (Figure 8). Most of the horizontal spacing units have been set at 640 acres, or a typical governmental section, with up to 2 wells allowed per section.

Another incentive for increasing horizontal drilling in South Dakota may be the recent update of the Procedures of the Board of Minerals and Environment (Article 74:09) and the Oil and Gas Conservation Rules (Article 74:10), which supplement the oil and gas conservation statute, cited as SDCL Chapter 45-9. The new rules became effective September 8, 1996. For example, prior to that date, an operator desiring to conduct a directional drilling operation had to file a petition with the secretary of the DENR for a contested case hearing before the South Dakota Board of Minerals and Environment (BME), a citizen advisory board appointed by the Governor. After notice and hearing, the BME could issue a permit for the directional drilling operation. Since the requirements for contested case hearings can be a time consuming and expensive process, and the rules did not address the complex issues associated with horizontal drilling, the DENR decided to address these issues with an update of the rules. Along with requiring some additional information to the application to drill a horizontal well, the major change in the rules that affects horizontal drilling is the addition of a new chapter 74:10:11:01, called the "Notice of Recommendation Procedure" or NOR. The NOR allows the DENR Oil & Gas Program staff to deal administratively with applications to drill horizontal wells if they are uncontested (Figure 9). Other applications that can now be handled by the NOR are exception locations, abandoning oil and gas fields, directional holes, multiple zone completions, commingling of oil from separate pools, and underground injection control (UIC) applications or modifications.

Although South Dakota has not yet enjoyed the amount and success of horizontal activity that our neighbors to the North have, there is great potential for increased drilling, horizontal and vertical, in the state. The Williston Basin encompasses portions of 16 counties in the state, over 28,000 sq. mi., and close to 18 million acres (Figure 10). Currently, only two of those counties, Harding and Dewey, have oil and gas production. And this production only affects about 30,000 acres. This leaves a vast, essentially unexplored, area that has the potential to greatly increase the oil and gas reserves of South Dakota.

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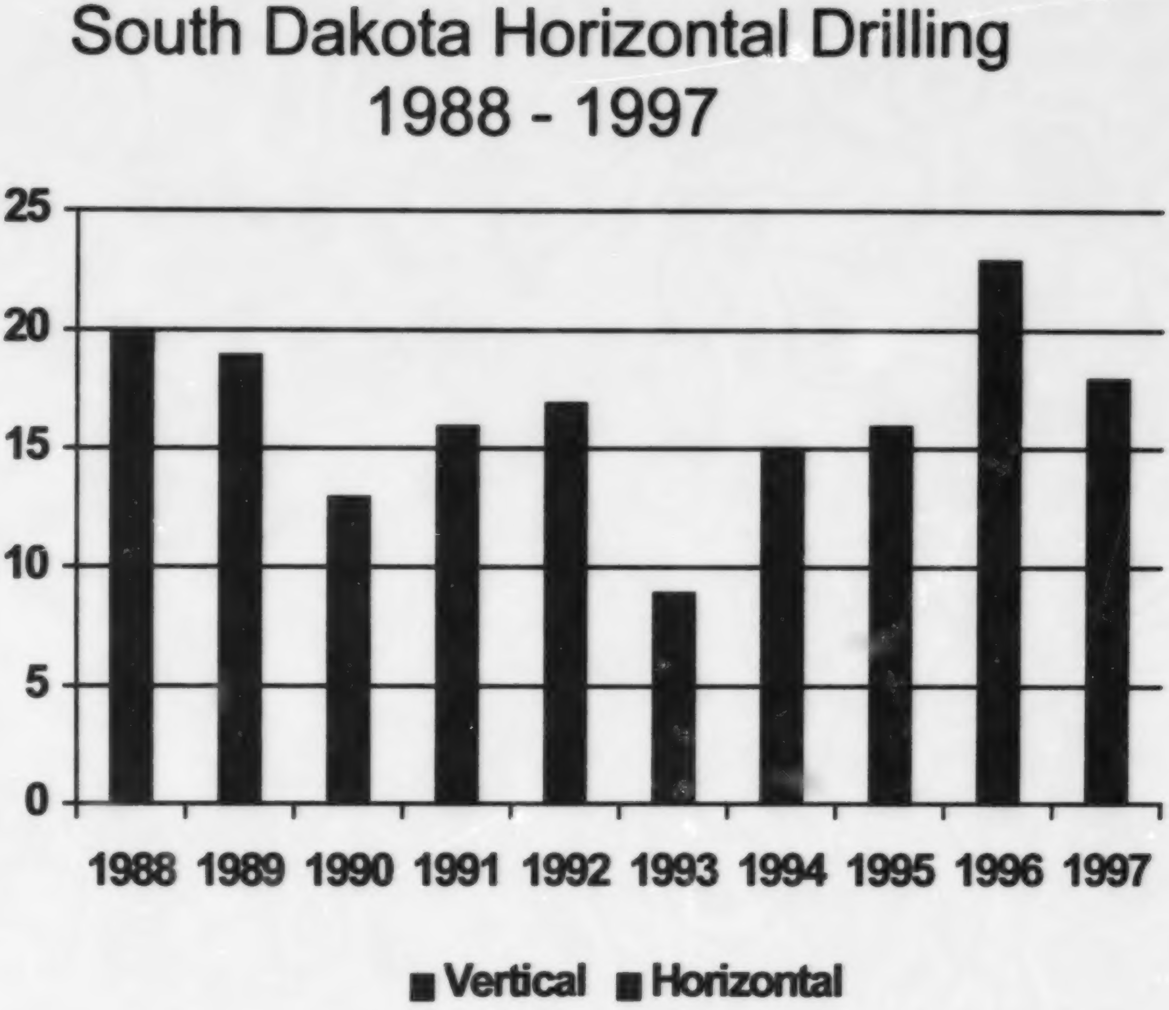
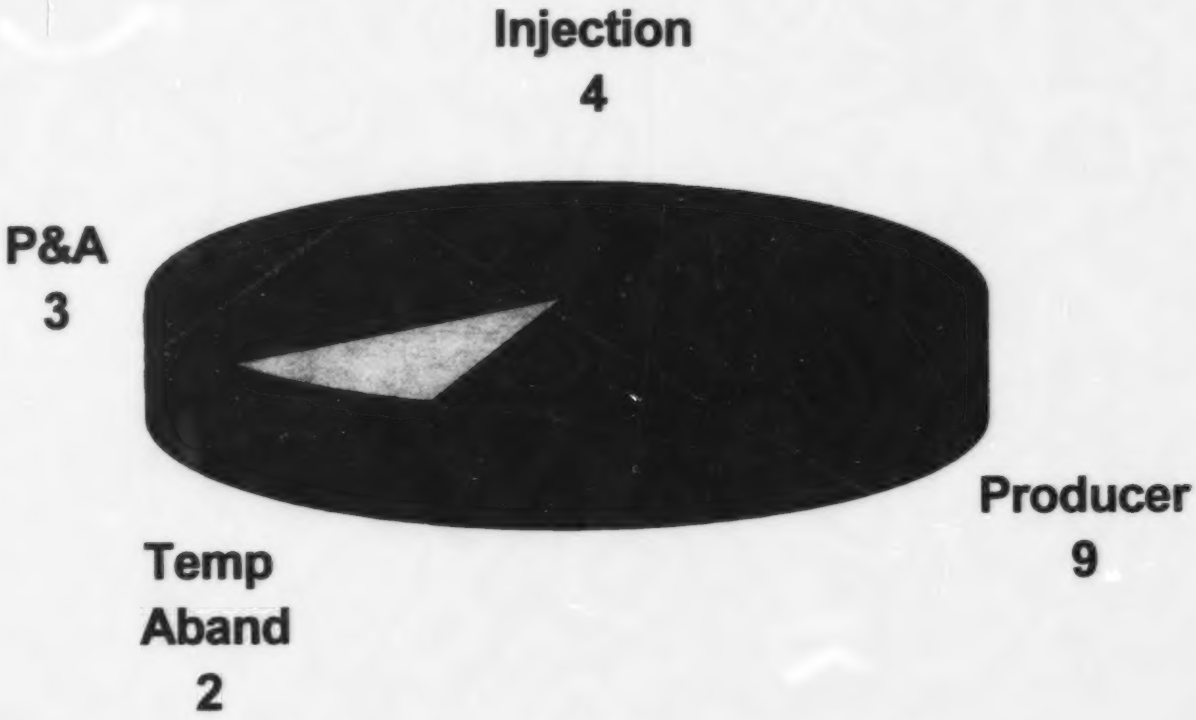


SD DENR - Oil & Gas Program 3/20/98 Figure 1

South Dakota Horizontal Wells
18 Wells as of March 1998



SD DENR - Oil & Gas Program 3/20/98 Figure 2

DEPCO, INC.
FEDERAL #42-27
SE NE SEC. 27-T22N-R5E
HARDING CO., SOUTH DAKOTA

ALPAR RES., INC.
CLARKSON #1-12
1850' FEL/500' FSL SEC. 12-T21N-R4
HARDING CO., SOUTH DAKOTA

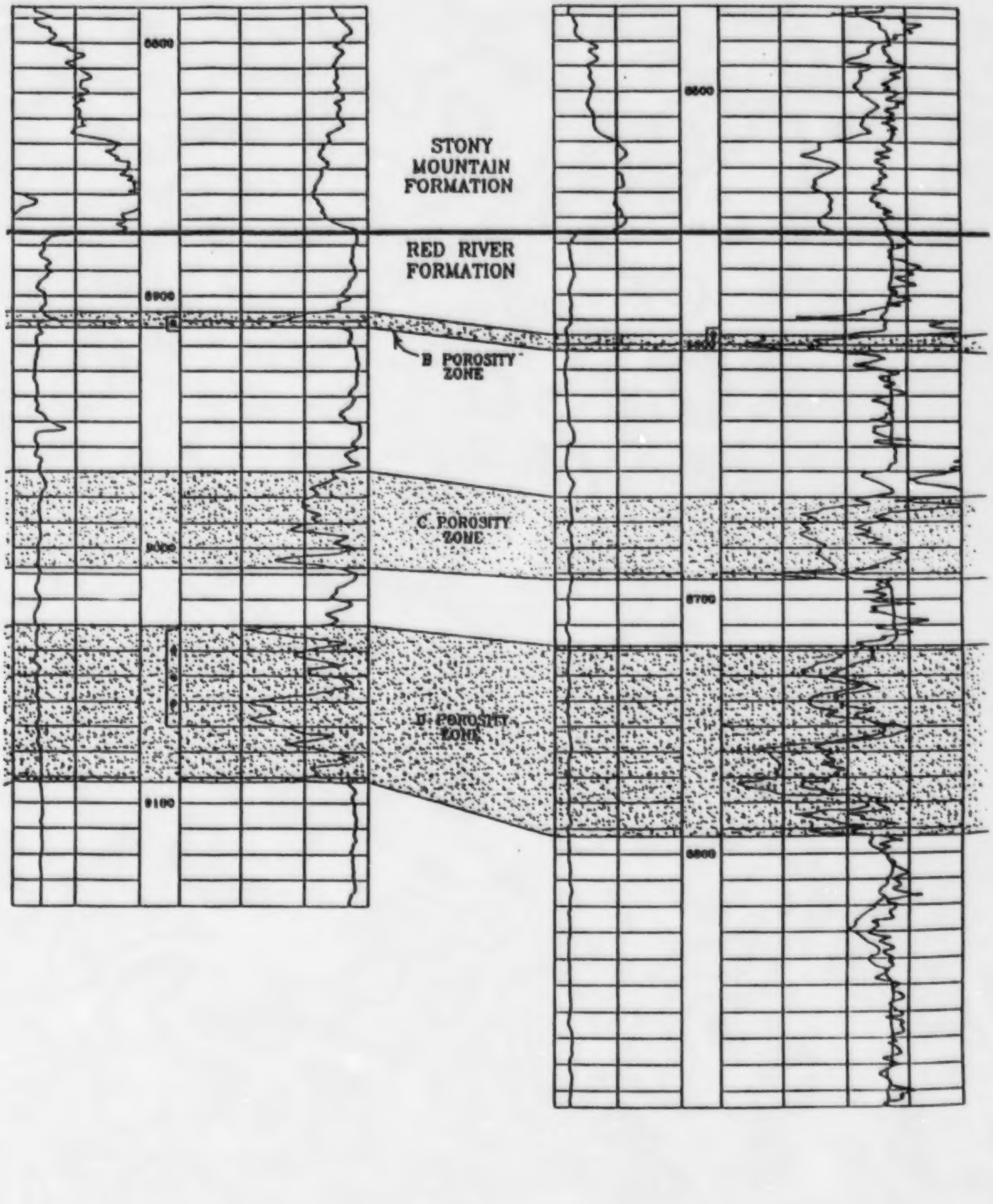


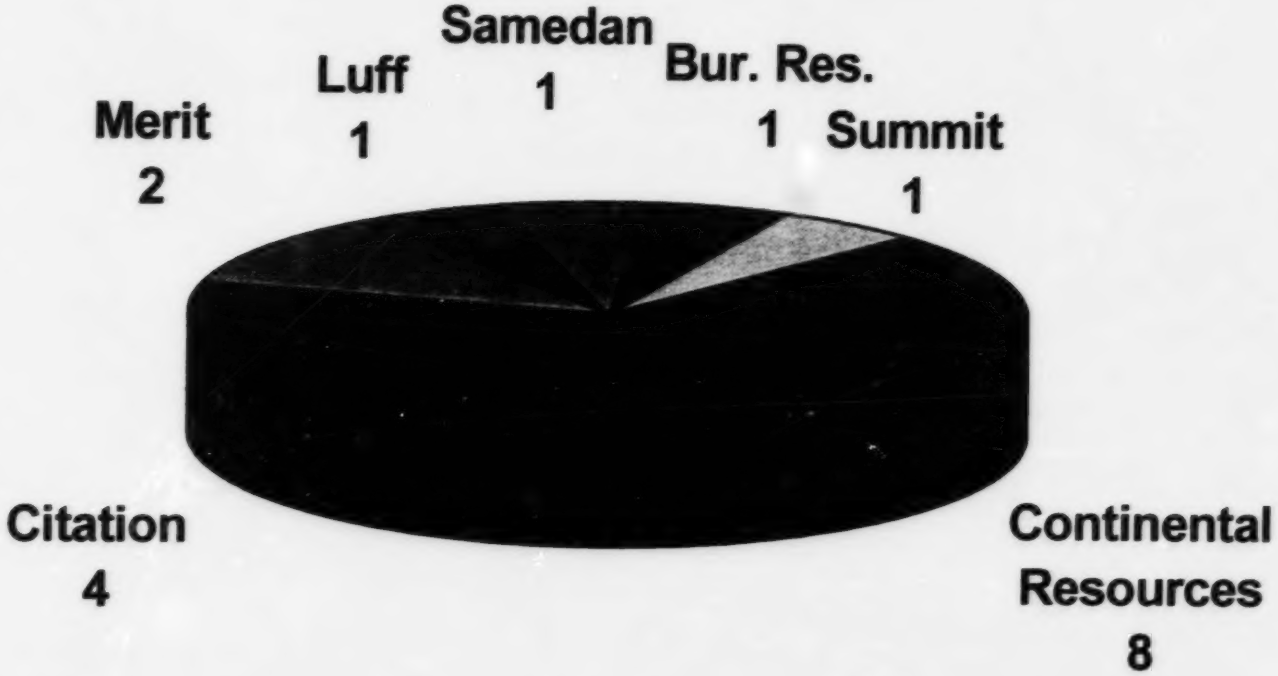
Figure 3 - Exhibit by Continental Resources, Inc. to SD Board of Minerals and Environment Hearing, 9/20/95.

Harding Co. Horizontal Wells 1988-1997

Well Name	Operator	Status	Spud Date	Depth	Lateral Length
[redacted]	Meidian Oil Co.	P&A	12/16/88	TVD-9124, MD-10,086	962
[redacted]	Citation Oil & Gas	Producer	9/25/94	TVD-8404,MD-11,200	2796
[redacted]	Citation Oil & Gas	Injection (Water)	11/6/94	TVD-8422, MD-11,300	2878
[redacted]	Merit Energy	TA	10/29/95	TVD-8324, MD-11,878	3554
[redacted]	Continental Resources	P&A	11/25/95	TVD-8714, MD-13,202	4488
[redacted]	Merit Energy	Producer	12/3/95	TVD-8857, MD-12,661	3804
[redacted]	Samedan Oil	P&A	7/12/96	TVD-8667, MD-13,127	4460
[redacted]	Continental Resources	Injection (Air)	9/11/96	TVD-8572, MD-13,406	4834
[redacted]	Continental Resources	Producer	10/17/96	TVD-8524, MD-13,633	5109 (longest lateral)
[redacted]	Citation Oil & Gas	Producer, re-entry	11/5/96	TVD-8444, MD-11,084	2640
[redacted]	Luff Exploration	Injection (Water)	11/15/96	TVD-9040, MD-10,059	1019
[redacted]	Citation Oil & Gas	Producer, re-entry	11/23/96	TVD-8470, MD-9374	904
[redacted]	Continental Resources	Producer	11/24/96	1:TVD-8330, MD-11,144	2814
				2:TVD-9042, MD-12,782	3740
[redacted]	Continental Resources	Producer	1/19/97	TVD-9625, MD-12,031	2406
[redacted]	Continental Resources	Producer	3/1/97	1:TVD-8646, MD-13,303	4657
				2:TVD-8527, MD-12,806	4279
[redacted]	Continental Resources	Injection (Air)	8/8/97	TVD-8390, MD-11,836	3448
[redacted]	Summit Resources	TA	8/10/97	TVD-8073, MD-11,404	3331
[redacted]	Continental Resources	Producer	9/10/97	1:TVD-8958, MD-11,003	2045
				S1:TVD-8935, MD-10,768	1833
				S2:TVD-8953, MD-11,012	2059
				2:TVD-8949, MD-11,592	2643

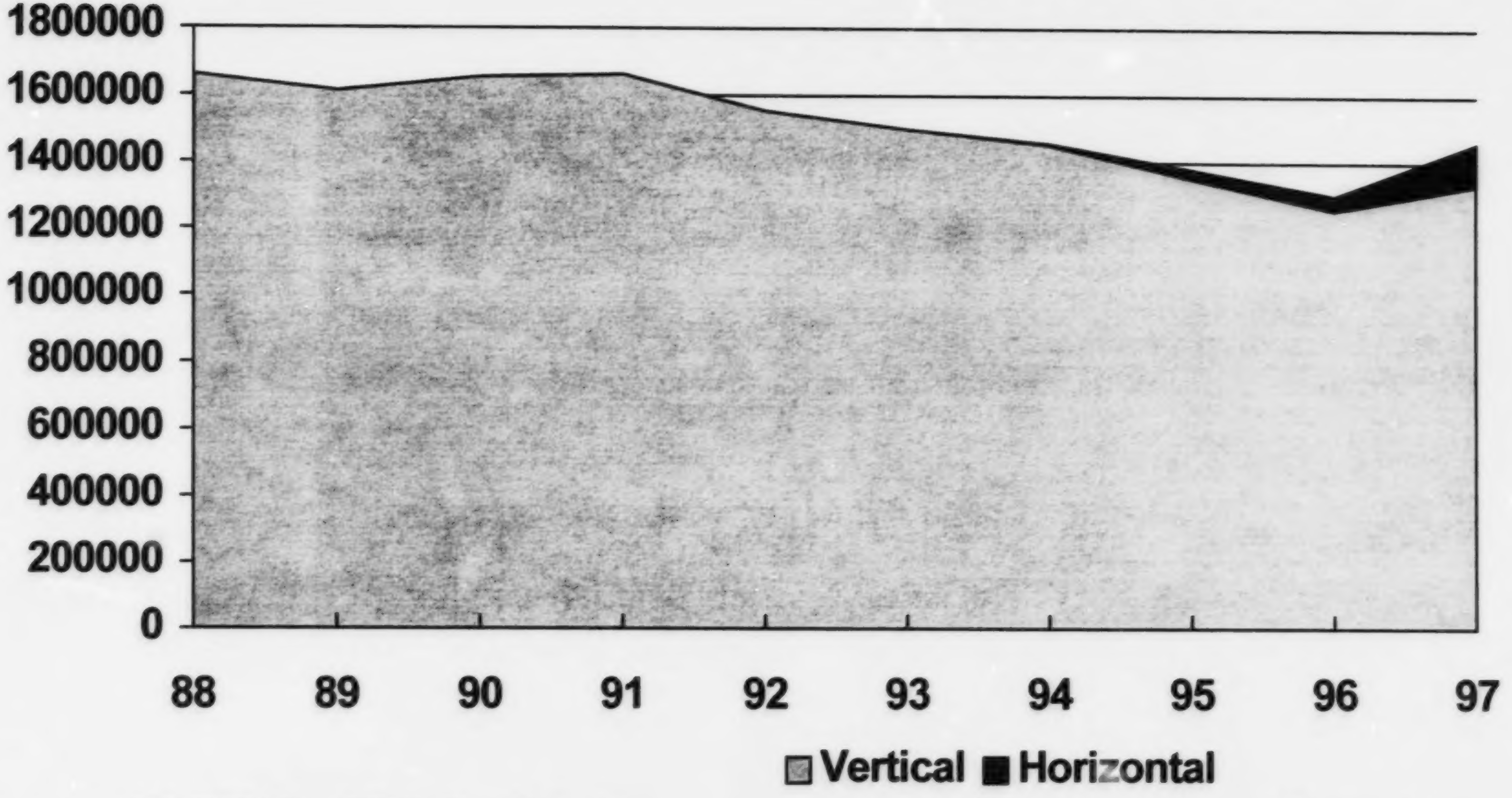
SD DENR - Oil & Gas Program 3/20/98 Figure 4

South Dakota Horizontal Well Operators
18 Wells as of March 1998



SD DENR - Oil & Gas Program 3/20/98 Figure 5

South Dakota 1988-1997
Yearly Oil Production (BBLS)



SD DENR - Oil & Gas Program 3/20/98 Figure 6a

Annual Horizontal Well Production
1994-1997 (page 1)

Well Name		1994	1995	1996	1997
Harper #6-21	O			0	0
Clarkson-WB'B'RR	G			0	0
SENW 21-21N-3E	W			483	2,492
40 063 20435	D			4	21
Apache #12-22H	O	4,211	27,422	18,954	17,685
WB"B"RRU	G	0	0	0	0
NESW 22-21N-3E	W	1,596	10,417	8,746	8,881
40 063 20505	D	30	360	353	365
CRI #23-25H	O			3,707	17,442
NENE 3-21N-3E	G			0	29,025
40 063 20532	W			10,367	42,289
WBRRU/SBRRU	D			60	646
CRI #23-30H	O			2,760	11,749
NENE 25-21N-3E	G			0	23,089
40 063 20532	W			7,037	33,402
SBRRU/WBRRU	D			60	346
CRI #31-8H	O			1,047	25,565
NENE 8-21N-4E	G			0	108,984
40 063 20533	W			11,936	94,223
BRRU	D			26	346
CRI #44-22H	O				8,102
NENE 27-21N-4E	G				21,725
40 063 20534.01	W				18,725
BRRU/SBRRU	D				317
CRI #41-27H	O				30,303
NENE 27-21N-4E	G				80,683
40 063 20534.01	W				77,520
SBRRU/BRRU	D				312

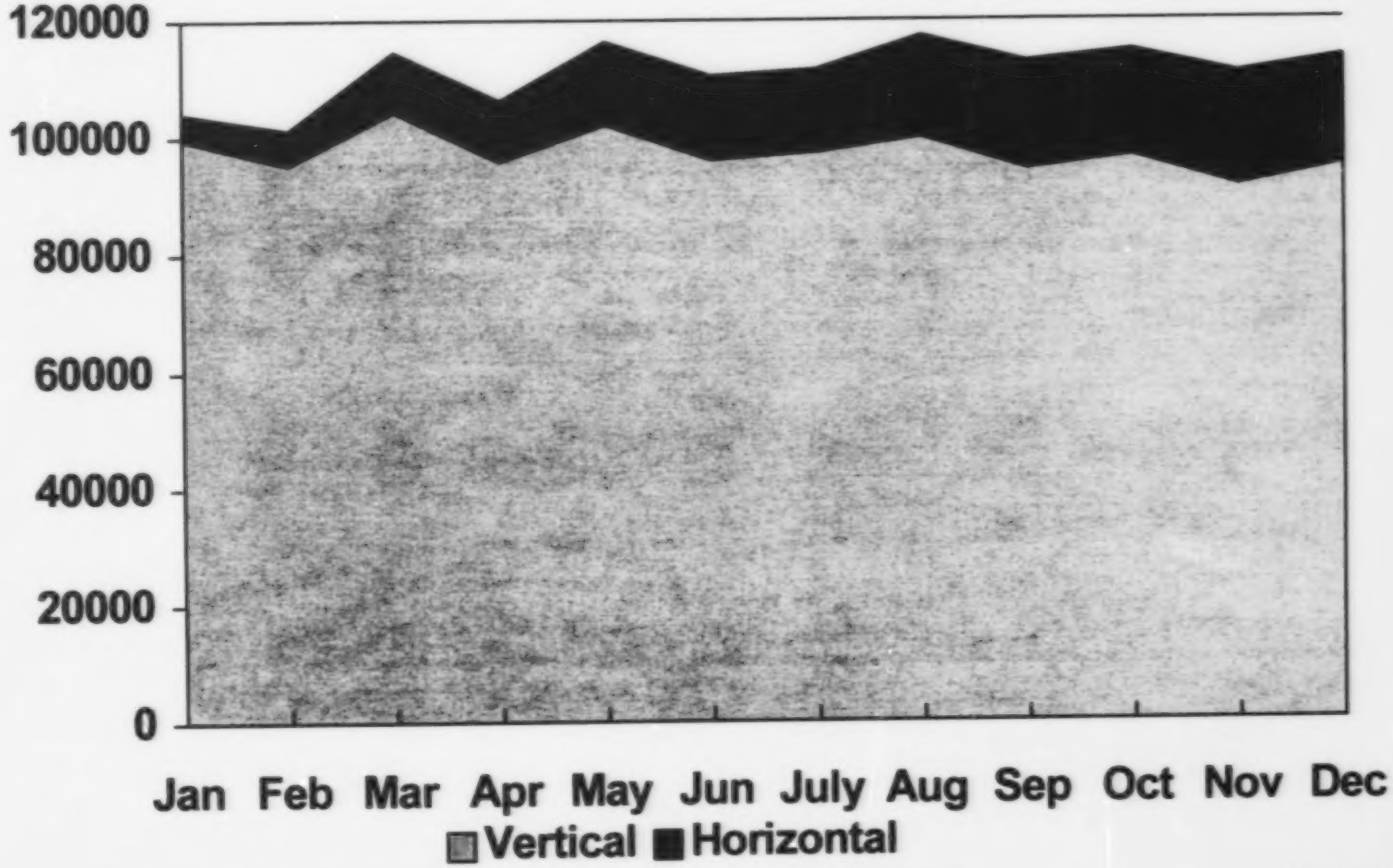
SD DENR Oil & Gas Program Fig. 6b
3/20/98

Annual Horizontal Well Production
1994-1997 (page 2)

Well Name		1994	1995	1996	1997
SESW 36-21N-4E	G				62,045
40 063 20535	W				101,771
SBRRU	D				224
Meridian #41-27H	O		4	459	0
Niemi	G		0	0	0
NENE 27-20N-5E	W		6,515	11,976	0
40 063 20520	D		22	28	0
Meridian #14-15H	O			17,696	11,712
State	G			0	0
SWSW 15-22N-3E	W			57,107	47,262
40 063 20523	D			298	315
Luff #M-20H	O				1,735
Stearns	G				88
SWSW 20-22N-4E	W				2,254
40 063 20536	D				43
CRI #1-19F Johnson	O				1,387
NWNE 19-21N-5E	G				0
40 063 20537	W				29,313
non-unit	D				74
CRI #1-7F	O				1,245
Table Mountain	G				0
SWSW 7-22N-4E	W				6,994
40 063 20550	D				19
TOTALS	O	4,211	27,422	44,164	126,925
	G	0	0	0	263,594
	W	1,596	10,417	95,676	363,355
	D	30	360	801	2,804

SD DENR Oil & Gas Program Fig. 6b
3/20/98

South Dakota 1997
Monthly Oil Production (BBLS)



SD DENR - Oil & Gas Program 3/20/98 Figure 7a

1997 OIL PRODUCTION BY COUNTY

COUNTY/FIELD	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Year-to-Date	Cumulative Production
CUSTER COUNTY														
Barker Dome	0	238	222	210	238	233	0	238	0	234	210	230	2,053	290,699
DEWEY COUNTY														
Lantry	444	342	409	95	0	0	0	0	0	0	0	0	1,290	121,753
FALL RIVER COUNTY														
Alum Creek	4,716	4,287	4,764	4,319	4,465	4,277	4,244	4,337	4,037	3,615	4,206	4,111	51,398	2,268,146
Cheyenne Bend	291	412	391	396	374	332	350	567	84	390	373	400	4,360	56,812
East Simms Draw	72	371	390	213	332	229	0	0	0	0	0	0	1,607	351,472
Edgemont	203	176	215	197	140	202	100	79	155	155	178	121	1,921	197,289
Igloo	78	77	61	11	102	100	73	35	0	0	0	73	610	51,707
Indian Creek	360	337	444	388	396	363	310	303	513	717	617	604	5,352	386,625
North Hollingsworth	258	314	375	387	450	170	0	0	0	0	0	0	1,954	583,987
Porter	1,405	1,262	1,413	1,387	1,305	1,401	1,469	1,465	1,302	1,314	1,255	1,242	16,220	221,771
Provo	0	0	0	0	0	0	0	0	0	0	0	0	0	13,203
Sheep Draw East	0	0	0	0	0	0	0	0	0	0	0	0	0	1,823
Fall River County Total	7,383	7,236	8,073	7,278	7,564	7,074	6,546	6,806	6,091	6,191	6,629	6,551	83,422	4,132,835
HARDING COUNTY														
Buffalo	81,178	78,082	87,986	82,629	92,429	86,911	88,621	93,977	91,592	91,788	88,514	90,982	1,054,689	21,807,404
Bull Creek	1,102	1,398	1,611	1,485	1,545	1,445	1,550	1,517	1,351	1,556	1,489	1,557	17,606	540,068
Clarkson Ranch	2,352	2,363	2,593	1,959	2,564	2,397	2,357	2,489	2,496	2,642	2,585	2,502	29,299	145,404
Corey Butte	222	298	256	280	228	200	212	217	247	271	218	244	2,873	90,854
East Harding Springs	1,055	1,196	1,271	1,042	1,268	1,136	1,276	1,302	1,226	1,273	1,118	1,263	14,426	654,617
Harding Springs	215	189	218	191	202	178	197	175	175	173	163	169	2,245	223,183
Jones Creek	1,257	1,248	1,313	1,268	885	1,357	1,365	1,367	1,321	1,264	1,304	1,358	15,307	552,587
Pete's Creek	1,542	1,344	1,430	1,342	1,334	1,251	1,238	1,146	1,120	1,128	1,071	1,000	14,946	25,484
South Medicine Pole Hills	1,540	1,376	1,543	1,315	1,499	1,473	1,503	1,437	1,410	1,478	1,418	1,438	17,430	861,797
State Line	1,380	1,213	1,324	1,278	1,263	1,264	1,239	1,076	937	1,160	1,045	1,078	14,237	812,320
Table Mountain	1,328	1,642	2,972	2,896	2,168	2,466	2,478	2,345	2,182	2,466	2,187	2,189	27,319	376,407
Travers Ranch	716	803	903	729	871	886	739	751	750	805	771	858	9,582	1,005,767
Unnamed	0	0	0	0	0	0	0	0	0	0	0	0	0	71,789
Yellow Hair	2,429	2,244	2,507	2,273	2,298	2,261	2,262	2,427	1,974	2,316	2,163	2,170	27,324	865,572
Harding County Total	96,296	93,396	105,927	98,667	108,554	103,225	105,037	110,226	106,781	108,320	104,046	106,808	1,247,283	28,033,253
STATE TOTAL	104,123	101,212	114,631	106,250	116,356	110,532	111,583	117,270	112,872	114,745	110,885	113,589	1,334,048	32,578,540

SD DENR Oil & Gas Program 3/17/98 Figure 7b

1997 Monthly Horizontal Well Production

Page 1

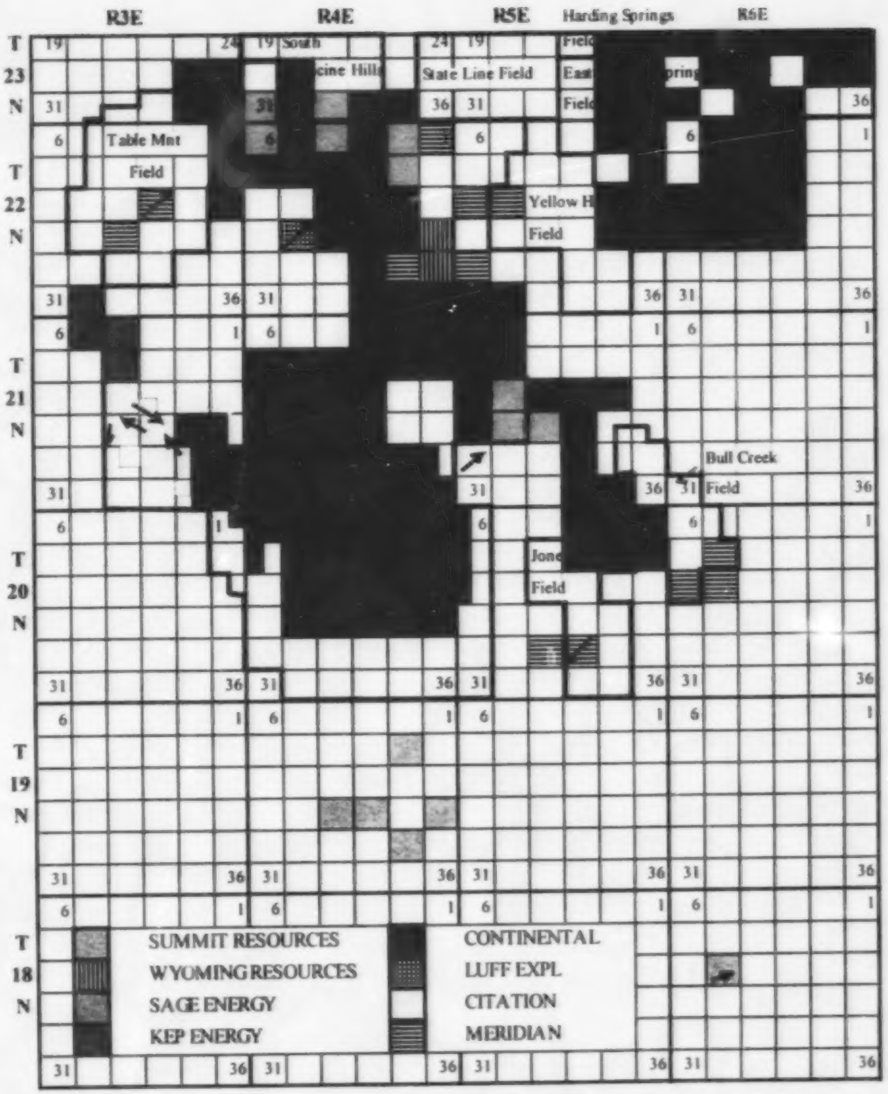
Well Name Location API Number		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Year-to-Date 1997	Cumulative Production
Clarkson-WB`B'RRU	G	0	0	0	0	0	0	SI	SI	SI	SI	SI	SI	0	0
SENW 21-21N-3E	W	1066	0	0	1426	0	0							2492	41,383
40 063 20435	D	11	0	0	10	0	0							21	1,279
Apache #12-22H	O	1,557	1,389	1,539	1,477	1,490	1,452	1,580	1482	1421	1472	1404	1422	17,685	68,272
WB"B"RRU	G	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NESW 22-21N-3E	W	729	672	746	714	760	728	752	771	741	761	744	763	8,881	29,640
40 063 20505	D	31	28	31	30	31	30	31	31	30	31	30	31	365	1,108
CRI #23-25H	O	1,571	1,373	1,387	1,328	1,501	1,405	1,620	1410	1095	1086	2378	1288	17,442	21,194
NENE 3-21N-3E	G	1,316	1,316	2,040	1,904	2,108	2,670	2,759	2759	2970	2916	2700	3567	29,025	29,025
40 063 20532	W	3,394	2,742	2,996	3,845	5,147	3,588	3,278	2378	2330	3638	5653	3300	42,289	52,656
WBRRU/SBRRU	D	28	28	30	28	31	30	31	31	28	27	325	29	646	706
CRI #23-30H	O	1,037	944	971	957	1,052	1,011	1,097	1108	871	768	1099	834	11,749	14,509
NENE 25-21N-3E	G	1,036	1,036	1,620	1,512	1,674	2,130	2,201	2201	2365	2322	2150	2842	23,089	23,089
40 063 20532	W	3,162	2,648	2,500	3,291	4,511	4,579	2,573	1676	1934	1865	2526	2137	33,402	40,439
SBRRU/WBRRU	D	28	28	30	28	31	30	31	31	28	27	25	29	346	406
CRI #31-8H	O	1,295	1,577	1,961	2,208	2,310	2,201	2,263	2001	2301	2370	3066	2012	25,565	26,612
NENE 8-21N-4E	G	0	8,370	8,990	8,680	9,610	8,310	8,587	8587	13794	12276	11880	9900	108,984	108,984
40 063 20533	W	6,091	6,079	9,341	7,576	9,456	7,753	6,322	6772	11236	8440	8104	7053	94,223	106,159
BRRU	D	24	27	29	28	31	30	31	31	29	31	30	25	346	372
CRI #44-22H	O		282	833	832	833	794	703	846	753	807	740	679	8,102	8,102
NENE 27-21N-4E	G		0	1,023	2,250	2,325	2,250	2,250	2387	2156	2387	2310	2387	21,725	21,725
40 063 20534.01	W		679	2,164	1,795	2,296	1,883	1,379	1745	1737	1893	1716	1438	18,725	18,725
BRRU/SBRRU	D		14	31	30	31	30	30	31	28	31	30	31	317	317
CRI #41-27H	O		920	2,820	2,917	2,950	3,140	2,546	3153	2914	2992	3412	2539	30,303	30,303
NENE 27-21N-4E	G		0	3844	7868	7868	8430	8430	9083	8204	9083	8790	9083	80,683	80,683
40 063 20534.01	W		3145	8361	7368	8383	9421	7968	5142	6467	7202	7950	6113	77,520	77,520
SBRRU/BRRU	D		14	31	28	28	30	30	31	28	31	30	31	312	312

SD DENR Oil Gas Program 3/20/98 Figure 7c

1997 Monthly Horizontal Well Production
Page 2

CRI #24-36H	O					2113	4198	4193	7360	8932	8202	7389	7514	49,901	49,901
SESW 36-21N-4E	G					0	0	0	10498	10860	12989	12570	15128	62,045	62,045
40 063 20535	W					2228	4673	10224	11511	20127	19402	15622	17984	101,771	101,771
SBRRU	D					14	28	31	29	30	31	30	31	224	224
Meridian #41-27H	O	0	0	0	0									0	463
Niemi	G	0	0	0	0	SI	SI	SI	SI	SI	SI	SI	SI	0	0
NENE 27-20N-5E	W	0	0	0	0									0	18,491
40 063 20520	D	0	0	0	0									0	50
Meridian #14-15H	O	0	402	1,571	1,490	1,035	1,166	1,055	1042	970	1068	948	965	11,712	29,408
State	G	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SWSW 15-22N-3E	W	0	2,581	4,840	6,480	6,851	3,664	3,782	3813	3213	3565	3630	4843	47,262	104,369
40 063 20523	D	0	14	31	30	31	30	31	31	27	31	30	29	315	613
Luff #M-20H	O				107	1628								1,735	1,735
Stearns	G				41	47	WSW	WSW	WSW	WSW	WSW	WSW	WSW	88	88
SWSW 20-22N-4E	W				459	1795								2,254	2,254
40 063 20536	D				15	28								43	43
CRI #1-19F Johnson	O					293	92	183	0	0	0	0	819	1,387	1,387
NWNE 19-21N-5E	G					0	0	0	0	0	0	0	0	0	0
40 063 20537	W					9,239	3,673	5805	0	0	0	0	10596	29,313	29,313
non-unit	D					27	11	16	0	0	0	0	20	74	74
CRI #1-7F	0												1245	1,245	1,245
Table Mountain	G												0	0	0
SWSW 7-22N-4E	W												6994	6,994	6,994
40 063 20550	D												19	19	19
TOTALS	O	4423	5943	10111	10359	14153	14448	14143	17294	18386	17997	19337	18483	165077	238622
	G	1316	9686	15897	20743	21958	21660	22026	33314	37984	39651	38250	40065	302550	302550
	W	11280	15898	28448	29663	46155	35383	39510	32132	45851	44901	43419	59084	431724	589275
	D	94	125	183	199	252	219	231	215	200	213	505	246	2682	5117

SD DENR Oil Gas Program 3/20/98 Figure 7c


R3E
R4E
R5E
R6E
Harding Springs
T 23 N
T 22 N
T 21 N
T 20 N
T 19 N
T 18 N
South
cine Hills
State Line Field
Field
East
Field
pring
Table Mnt
Field
Yellow H
Field
Bull Creek
Field
Jone
Field
SUMMIT RESOURCES
WYOMING RESOURCES
SAGE ENERGY
KEP ENERGY
CONTINENTAL
LUFF EXPL
CITATION
MERIDIAN

Horizontal Spacing in Harding Co.

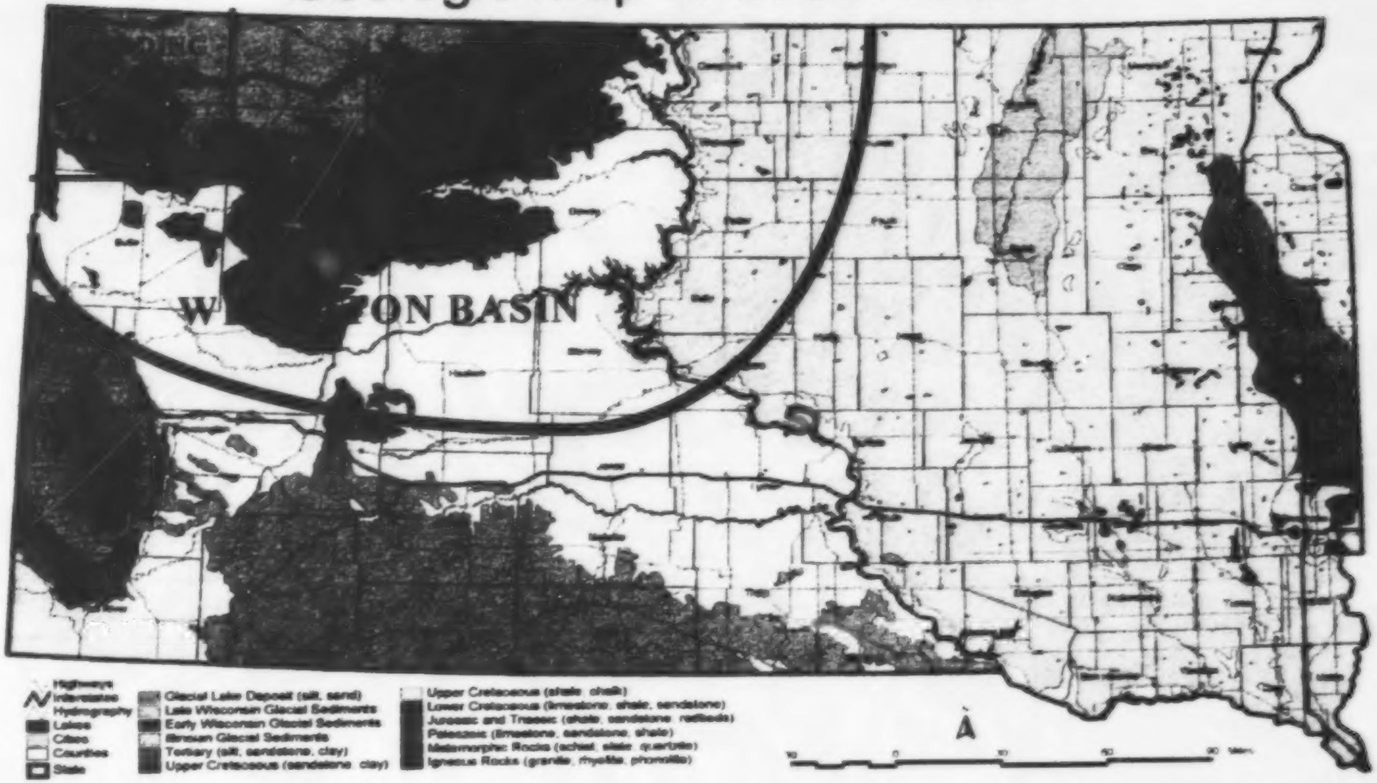
SD DENR
Oil & Gas Program
3/20/98
Fig. 8

Notice of Recommendaton Procedure

- Application is made and reviewed by DENR
- DENR publishes NOR, usually with conditions.
- Allow 20 days from publication date for comments.
- If no objections, O&G Supervisor approves the application administratively.

If objections made, a hearing is scheduled before the Board of Minerals and Environment.

Geologic Map of South Dakota


WILLISTON BASIN
Highways
Interstates
Hydrography
Lakes
Cities
Counties
State
Glacial Lake Deposit (silt, sand)
Late Wisconsin Glacial Sediments
Early Wisconsin Glacial Sediments
Illinoian Glacial Sediments
Tertiary (silt, sandstone, clay)
Upper Cretaceous (sandstone, clay)
Upper Cretaceous (shale, chalk)
Lower Cretaceous (limestone, shale, sandstone)
Jurassic and Triassic (shale, sandstone, redbeds)
Paleozoic (limestone, sandstone, shale)
Metamorphic Rocks (schist, slate, quartzite)
Igneous Rocks (granite, rhyolite, phonolite)
Miles

SD DENR - Oil & Gas Program 3/20/98 Figure 10

Horizontal Drilling: Technical Success But a Legal Quagmire

E. Craig Lothian
Gerrand Rath Johnson
Barristers & Solicitors

HORIZONTAL DRILLING: TECHNICAL SUCCESS BUT A LEGAL QUAGMIRE

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I. INTRODUCTION

One of the primary "engines" of both exploration activity and production success in Saskatchewan has been technologically driven by the proliferation of horizontal drilling. It should come as little surprise that legislators, lawyers and landmen have been slow to react to the legal and contractual environment which the industry has created through its technological advances.

This paper represents a summary review of some of the unique legal concerns and issues which have arisen (and continue to arise), as a result of the advent of horizontal drilling.

II. LEGAL ISSUES CREATED BY HORIZONTAL DRILLING

1. The *Kennibar Resources* decision: A "Wake-up Call"

In Saskatchewan, judicial notice of the fact that technological advances in drilling had out-paced existing legislation occurred in late 1990, in *Kennibar Resources Ltd. v. Saskatchewan (Minister of Energy & Mines) and Gulf Canada Resources Ltd.*[1]

In the *Kennibar* case, Gulf applied for and obtained permission from Saskatchewan Energy & Mines ("SE&M") to drill a Horizontal Well at Ingoldsby, Saskatchewan, and to produce the well in accordance with Good Production Practice ("GPP"). Although neither the Act nor any Regulations then in force in Saskatchewan authorized or defined GPP, SE&M adopted the concept from Alberta, which is essence allows the Operator to produce a Well without any restrictions on the maximum allowable rate of production ("MARP"). The proposed Gulf horizontal well was situated laterally adjacent to four vertical wells owned by Kennibar, and Kennibar objected to both the drilling of the wells and to GPP, for fear of unfair drainage. SE&M rejected Kennibar's objections and refused to put the matter to the Oil & Gas Conservation Board, (In fact at the time of the Board had not been constituted).

Kennibar appealed to the Saskatchewan Court of Queen's Bench. Scheibel J., held that the Minister had erred in law by allocating the Gulf Horizontal well a drainage unit of 160 acres. The Ingoldsby Pool required 40 acre spacing per well, pursuant to existing Minister's Orders and The Oil and Gas Conservation Act (as it then existed). The Court quashed the Minister's Order approving the drilling of the well --- which in turn required Gulf to temporarily shut-in its well (which was producing in excess of 900 bbls./day). Subsequent to the *Kennibar* decision, the legislation (which at page 46, Mr. Justice Scheibel noted had "failed to keep pace with the new advances in the industry"), was summarily amended.

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[1] (1991) 88 Sask. R. 35

2. Horizontal Well Spacing

Prior to the onset of horizontal drilling, the concept of Spacing Units or Drainage Units ("DSU's") was reasonably simple and well understood. In fact, the concept was of sufficient certainty in Canada, that the drafters of Leases, Farmout Agreements, Seismic Option Agreements and the like often adopted the practice of defining a "Spacing Unit" as being equivalent to that area allocated to a well from time to time, as prescribed by or under any statue, regulation, order or directive of any government or governmental agency. The extent to which this has occurred in Canada is largely a result of the fact that it is reflected in the standard form Petroleum and Natural Gas Lease (and now the standard form Farmout Agreement) endorsed by the Canadian Association of Petroleum Landmen ("CAPL"), has achieved widespread acceptance in the industry.

The Producers 88 - Paid Up Lease form commonly utilized at least in North Dakota and Montana, does not adopt the term "spacing unit" , but rather utilizes the more comprehensive term "leased premises". Nevertheless, the Producers 88 Leases are typically modified by way of the attachment of an Addendum Agreement, and I have observed several instances where the Addendum Agreement amended the Lease as follows:

> Notwithstanding anything to the contrary contained in the lease, at the end of the primary term of the lease, a well capable of production shall hold beyond the primary term only those lands covered by the leases which are located within the spacing unit as set forth from time to time by the State of [Montana/North Dakota].

I am uncertain as to whether or not the legislative or regulatory regimes in those jurisdictions, do in fact set forth or prescribe a "spacing unit" for horizontally drilled wells.

In Saskatchewan (Pre-horizontal drilling), a preliminary determination as to the under such an agreement was accomplished simply by contacting SE&M and inquiring as to the prescribed DSU or wells in the location in question. If a more certain determination was required, the prescribed DSU could be determined by reference to *The Oil & Gas Conservation Act*, (the "OGCA"), *The Oil & Gas Conservation Regulations* (the "OGCR"), and any Minister's Orders and/or Circulars made thereunder. Thus, a "spacing unit" (which is generally a critical term in such agreements) was the equivalent of a vertical well "drainage unit" as defined in Section 2(1)(d) of the OGCA. Unfortunately, (at least in Saskatchewan) the level of certainty on this issue relating to vertical wells is lacking for horizontal wells.

Neither the OGCA or the OGCR (nor any Policy Directive or Circular) defines a "spacing unit" or a drainage unit for horizontal wells. For technical reasons, and to maintain minimum set-back distances, horizontal wells typically are not drilled on the vertical DSU pattern, but often (or perhaps generally) intersect two or more Legal Subdivisions, which

3. Horizontal Wells and Offset Obligations

It is my opinion that the standard definition of a "spacing unit" found in CAPL Leases (and certain non-CAPL versions) creates a further operational and legal pitfall for companies. Given that the Producers 88 Lease forms in vogue in the United States do not typically include provisions imposing offset well obligations on the Lessee, this is generally not an issue of concern in those jurisdictions.

An "offset well" is defined in paragraph 1(f) of the CAPL Lease to mean "any well drilled on any spacing unit laterally adjoining the said lands ...". This clause, which was adequate when all wells were drilled more less directly into the subsurface beneath the surface location, fails conceptually when wells are being drilled off a surface location into adjoining lands. As we are all aware, the surface location of a horizontal well generally is not representative of the actual location from which the oil is being extracted. Often the surface location of the well is situated on lands under which the minerals are not even under lease by the operator of the well. Clearly, the location at which the well is "**drilled on**" is irrelevant.

(a) Multiplicity of Offsets

It is my opinion that the current definition contained in CAPL Leases, represents a potential "lose-lose" litigation scenario for oil companies. While I am reluctant to record my views in this regard in writing, I am of the opinion that oil companies are at a significant disadvantage when involved in litigation against a Lessor. Even where the Lessor owns a substantial number of mineral titles or has a large successful farming operation --- the legal proceedings will appear to be a battle of "David and Goliath", or even worse, "Big Oil" versus "The Little Guy". While I am certain that these dynamics are at play in the Courts of Saskatchewan, I suspect that they exist in other jurisdictions as well.

With this preamble in mind, I commonly advise my oil company clients, that unless they are not just legally right, but morally right as well, they would be well-advised to avoid litigating issues arising out of a dispute with a Lessor under a Petroleum and Natural Gas Lease.

In addition to the non-legal impediments faced by oil companies in such situations, there are also certain contractual issues which will arise. As previously stated, I view the current Offset clause to represent a potential "lose-lose" scenario for the Lessee. Specifically, it is my opinion that the current definition is arguably either inaccurate, or at best creates some uncertainty or ambiguity as to its true meaning.

Courts, both in Canada and in the United States have adopted a variety of rules to aid them in the "proper" interpretation of documents. One such rule is described by the Latin phrase comprise parts of two or more conventional DSU's. This fact, combined with the lack of definitional certainty, results (in my opinion) in a breakdown of conventionally drafted Leases and other agreements (including CAPL versions), if those agreements simply define a spacing unit by reference to that "defined" by a government Act or regulation. While this issue has yet to be put before the Courts of Saskatchewan (nor any other jurisdiction to my knowledge), it is I suspect only a matter of time before that occurs. The issue is "ripe" for litigation.

While traditional drafting is perhaps deficient on this point, it is submitted that for Leases entered into in Saskatchewan, certainty can be achieved relatively simply. Minister's Order number MRO 501/93, defines a "Block" as being an "area approved by the Minister consisting of a drainage unit or a combination of drainage units traversed by or immediately adjacent to the productive horizontal sections of horizontal Wells."

This terminology is similarly adopted by SE&M for purposes of licensing Horizontal Wells, where the term "Drainage Area" ("DA") is deemed to be equivalent to the Block defined in MRO 501/93. The DA is then recorded on the Well Licence, which is a public record. In the event that the Horizontal Well is not drilled in the manner set out in the Well License Application the DA may be subject to change, which will be similarly reflected on the Well License. In some circumstances, a Drainage Unit is specifically defined in a Minister's Order, namely, where the Drainage Unit contains Crown and Freehold Lands, or where lands are Pooled to form a Drainage Unit.

To avoid the risk that a CAPL Lease or Farmout Agreement may fail to define a "spacing unit" for horizontal wells, I have adopted the practice of including the following provision in an Addendum Agreement:

> The "spacing unit" for a Horizontal Well (as defined by the appropriate statue, regulation, order or directive of any government or governmental agency), shall be deemed to be that area forming the Drainage Unit specified in a Minister's Order, where such Order is made, and in all other cases shall be deemed to be the Drainage Area for the well prescribed by Saskatchewan Energy & Mines (as set out in the Well Licence), or as amended upon completion of the Well.

While I am unfamiliar with the law south of the 49th parallel (and certainly not licenced to practice law outside the province of Saskatchewan), I would suggest that attorneys and landmen in jurisdictions other than Saskatchewan, should review their precedent documentation carefully to determine if a similar definitional "gap" exists.

The unfairness of this position is unquestionable. However, given that lawyers hate to lose, I would much rather be arguing this issue on behalf of the Lessor than the Lessee.

Nevertheless, while the potential problem is perhaps great, the solution (at least for CAPL Leases), can in my opinion be easily remedied by deleting the words "drilled on" and substituting the words "producing from" instead. Once amended the provision focuses not on where the bit went into the ground, but rather where the oil is coming from. This also conforms with SE&M policy regarding Crown offsets, as section 52 of *The Petroleum and Natural Gas Regulations, 1969*, deems any vertical well drainage unit which contains any portion of the productive horizontal section of a horizontal well, to contain a 'well' for the purposes of creating and fulfilling offsets.

(b) Vendor's Representations & Horizontal Offsets

The foregoing discussion creates a legal back-drop for an issue of potential concern in the acquisition and disposition of oil and gas assets. Purchase and Sale Agreements sometimes contain the following provision under Vendor's Representations:

> Offset Wells
>
> To the best of the Vendor's knowledge, there are not in existence under any of the Leases, or otherwise with respect to the Lands, any obligations requiring the Vendor to drill a well in a spacing unit offsetting any other well, whether or not that other well is located on the Lands.

We recommend that Vendors delete the representation regarding Offset Wells, by virtue of the considerable uncertainty which has arisen as a result of the proliferation of horizontal drilling in Saskatchewan. If we accept that under traditionally drafted Leases we are unable to precisely determine the "spacing unit" for a horizontal well, it necessarily follows that we are equally unable to determine whether or not horizontal wells drilled adjacent to the Lands being sold, constitute an "offset well". Thus, to provide such a representation would again seem to be simply an invitation to litigation.

III. CONCLUSION

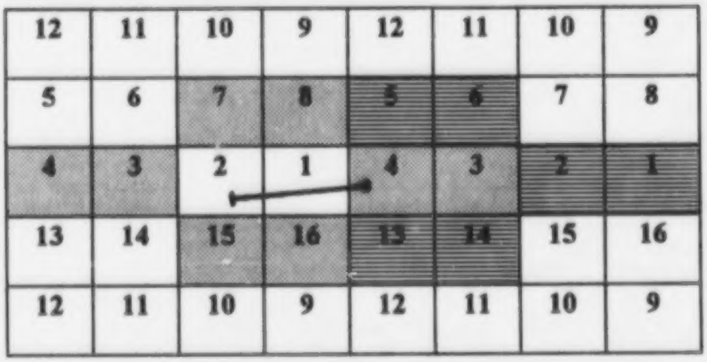
While exploration and development of oil is, from a technical perspective largely the same throughout the Williston Basin, it is important to remember that there exist significant differences between the legal and political regimes in each jurisdiction. While companies must be quick to embrace technological advances, the potential legal consequences must not be overlooked.

ecl\misc\hznt-cnf.doc

contra proferentum, meaning an ambiguous provision is construed against the party who prepared the agreement. In the oil and gas industry, Petroleum and Natural Gas Leases are generally standard form documents which are clearly drafted by the industry. Thus, the *contra proferentum* rule would result in an ambiguous provision (such as the Offset Well definition) being construed in such a way as to favour the Lessor. Unfortunately for Lessees, such an interpretation can result in two entirely different, but equally unsatisfactory results.

By way of example, Figure 1 below indicates a possible situation where a number of landowners could (in my opinion) argue that their lands are being "Offset", and the Lessee of their lands could be forced to either drill a Well on the "offsetting" DSU, surrender the DSU or pay compensatory royalties.

Figure 1. (80 acre DSU's laying down)



12	11	10	9	12	11	10	9
5	6	7	8	5	6	7	8
4	3	2	1	4	3	2	1
13	14	15	16	13	14	15	16
12	11	10	9	12	11	10	9

Specifically, a horizontal well drilled from Lsd. 4 in one section, to Lsd. 2 in the adjoining section can arguably create as many as seven (7) offset obligations under the current CAPL definition. Those DSU's which are laterally Offset by the productive horizontal section of the Well, are at risk of drainage and therefore the spirit and intent of the Offset Well clause could be invoked by the Lessor to argue that an Offset obligation exists despite the emphasis in the Lease to the location at which the Well is "drilled on". Such DSU's are marked in the above example, as:

▒

On the other hand, those DSU's which are laterally Offset by the actual location at which the Offset Well was "drilled on", can argue that an Offset obligation exists by virtue of the plain language utilized by the Lease, or alternatively, could argue that any ambiguity should be construed against the Lessee. Such DSU's are marked in the above example, as:

▤

F

Enhanced Oil Recovery Using Carbon Dioxide: "The Decision Process" and Review of the Williston Basin CO_2 Pipeline Project

Ray P. Hattenbach
Dakota Gasification Company

ENHANCED OIL RECOVERY USING CARBON DIOXIDE

"THE DECISION PROCESS"
&
REVIEW OF THE WILLISTON BASIN CO_2 PIPELINE PROJECT

Ray P. Hattenbach
Dakota Gasification Company

The use of carbon dioxide for enhanced oil recovery has been in use by the oil industry for almost 30 years. The interest has peaked and subsided several times during this time span and today finds us in another period where interest has peaked again. The major reasons for this increased interest is the success that has been achieved in the Permian Basin of Texas and the availability of a reliable supply. A dependable CO_2 supply source is critical in any enhanced oil recovery (EOR) endeavor. In Texas, a new pipeline has been extended from the Bravo Dome in New Mexico into the Texas Panhandle area and is fostering the development of numerous CO_2-EOR projects. Recent discoveries of CO_2 in Arizona now have owners of fields in southern California considering CO_2-EOR. The latest event of major interest to Williston Basin operators is the announcement by Dakota Gasification Company that it is proceeding with the construction of a 204.5 mile CO_2 pipeline from its Great Plains Synfuels Plant near Beulah, ND to PanCanadian Petroleum Limited's Weyburn field in southeastern Saskatchewan. The pipeline will have the capacity to deliver more than 200 MMSCF/D of CO_2 to oil fields in the Williston Basin. (Figure 1)

In July 1997, Dakota Gasification Company and PanCanadian Petroleum Limited signed a supply agreement whereby Dakota will supply PanCanadian up to 95 MMSCF/D of CO_2 for the Weyburn Field in southeastern Saskatchewan. The current project schedule calls for first delivery of CO_2 to Weyburn in December 1999. Numerous technical studies and a tremendous amount of planning were undertaken by both companies before the contract could be signed.

Over the past year several independent producers have approached DGC about the availability of supply of CO_2 and its cost delivered to their fields. In several instances these companies had not yet initiated any studies or modeling to determines the feasibility of implementing a CO_2 miscible flood nor did they have any idea as to the quantity of CO2 that would be required or the length of time required for a full filed injection. It is impossible for DGC to provide delivery and price information unless the oil producer can provide a demand forecast which DGC can then use to determine what its investment will be to deliver product to the field.

Today, I would like to review the technical studies and plans that are involved by both the oil producer and the CO_2 supplier before these two parties can reach agreement on a supply contract. First it is important to understand that CO_2 miscible flooding is no longer an experimental oil recovery method. After 30 plus years of use in the Permian Basin and other areas, including a field near Joffre, Alberta, Canada CO_2 miscible flooding can be classified as a true, proven recovery method. Because of its extended use in the light oil reservoirs in the Permian Basin, there is a better understanding of how CO_2 works and a clearer awareness of the operational and reservoir prerequisites required for an economically successful project. This knowledge, when applied to your reservoirs, can greatly reduce the risk in undertaking a CO_2-EOR project.

First one needs to understand why CO_2 makes a good solvent for EOR. CO_2 is miscible at lower pressures than natural gas or nitrogen. Even though CO_2 is considerably less viscous than the reservoir oil, at reservoir conditions it is two to three times more viscous than natural gas or nitrogen, thereby providing better horizontal and vertical sweep efficiency. It is also three to four times more dense than natural gas, thereby minimizing gravity overriding. The increased recovery achieved with the use of CO_2 is due to the phenomenon that it provides both miscible and immiscible benefits. Initially when the CO_2 is introduced into the reservoir it is not miscible with the oil. It mixes with the reservoir oil extracting hydrocarbons and producing a solution gas drive front. It also reacts with the formation water to increase its viscosity thereby reducing its producibility. This initial contact phase is not exceptionally efficient in recovering additional oil. As more CO_2 is injected and the pressure increases the CO_2 reacts with the oil to greatly reduce the viscosity, increasing oil bulk and relative permeability, thereby generating a miscible mixture which is more easily displaced than the original reservoir oil. (Figure 2)

Now that one understands what occurs when CO_2 is used as a miscible fluid, one needs to have an appreciation of what reservoir and geological data are needed for the technical studies to determine the economic viability of CO_2-EOR. The important factors that determine if CO_2 and the reservoir oil are miscible or not are: purity of CO_2, characteristics of the reservoir oil, temperature, pressure and reservoir parameters which control the amount of contact between the oil and the CO_2, i.e., the degree of mixing the two fluids. The following discusses these factors and what must be known for an effective evaluation to be conducted:

CO_2 Purity

Pure CO_2 is considered best for injection but is not available in the Williston Basin. Contamination by methane decreases the miscibility pressure, but up to 10% methane can be tolerated. The presence of hydrogen sulfide provides a beneficial effect since it lowers the miscibility pressure, but does have its side effects of corrosion, health hazard and odor. Most fields in the Williston Basin produce natural gas which already contains hydrogen sulfide which the operators are accustomed to handling. DGC's CO_2 as shown, does contain about 1% hydrogen sulfide and 0.6% methane (Figure 3)

Minimum Miscibility Pressure

Probably the most critical requirement for effective displacement of oil by CO_2 is a sufficiently high reservoir pressure. The pressure at which effective displacement occurs is know as the miscible pressure. There are several methods for estimating the minimum miscibility pressure, the most reliable being the method developed by Yellig and Metcalfe which relies on reservoir temperature and bubble-point pressure data. The minimum miscibility pressure is usually above 1200 psi. which requires a depth greater than 2500 feet in order not to exceed the reservoir fracture gradient.

If the reservoir pressure is below the minimum miscibility pressure, miscibility between the CO_2 and oil cannot be achieved. CO_2 can still be used to recover additional oil for these low pressure reservoirs because it can swell the oil and reduce its viscosity. The use of CO_2 for immiscible gas displacement is not as efficient as the miscible method because of the lower oil displacement that occurs. Solution gas drive and hydrocarbon displacement mechanisms also contribute to oil recovery by CO_2 immiscible flooding because the CO_2 is considered to be an effective displacing gas to achieve the above mechanisms at relatively low pressure.

Crude Oil Characteristics

Oil gravity of less than 25° API is sometimes considered unfavorable depending upon other characteristics of the reservoir. Some fields with crude oil having a gravity as low as 16° API have used CO_2 miscible flooding to successfully recover additional oil. Residual oil saturation is of more importance than oil gravity. A saturation of 25% is usually considered the minimum desirable. Oil viscosity should be lower than 15 centipoise.

Reservoir Parameters

Formation type can be either carbonate or sandstone. Reservoirs in the Williston Basin are typically low permeability carbonates. Permeability is of importance as it is for any producing reservoir. Horizontal permeability is important but not as critical as one might expect. The ratio of vertical to horizontal permeability, K_v to K_h is important. The ratio determines the rate at which the CO_2 can segregate in the reservoir. Thin permeability zones in the reservoir can be a plus since they can minimize the possibility of gravity override occurring. On the other hand, thicker permeable zones have more oil to recover.

Water

Salinity of connate water in a reservoir being considered for CO_2 -EOR is important since it affects the solubility of CO_2 in the water. CO_2 solubility is lower in brine water than in fresh water. The solubility of a gas in a gas-liquid solution normally decreases as the concentration of an electrolyte in the liquid increases. In the Williston Basin, reservoir salinity can range from 91,000 to 365,000 ppm total solids. Equilibrium solubility of CO_2 in reservoir water can vary from 50 to 125 scf/bbl for 100,000 ppm brine and from 5 to 75 scf/bbl for 200,000 ppm brine.

Reservoir Temperature

Reservoir temperature is not an important factor but it does have some impact on the evaluation. There is a strong relationship between the minimum miscible pressure, the bubble-point pressure of the crude and the reservoir temperature. Temperature is also a factor in determining the volume occupied by CO_2 at reservoir pressure.

These reservoir properties then need to be used in a model to determine the CO_2 requirements for a miscible flood. There are several simulation models available which can be used to screen potential fields.

DOE Predictive Model
DOE Prophet Model
Shell Spreadsheet

Simplified Displacement Model

The use of these models can then provide:

Estimate CO_2 Requirements

- Daily & Annual Volumes Required
- Number of Years Supply is Required

Determine Gross CO_2 Utilization
Estimate Oil Recovery Potential

Some independent oil producers may not have the technical staff on board to undertake this type of analysis. DGC has worked with several reservoir engineering consultants over the past several years and can make available a list of consultants that can provide assistance. Once these determinations have been made, it is then time to initiate discussions with potential CO_2 suppliers. With a demand forecast for the field based on the field simulations the CO_2 supplier can then determine:

Size of Pipeline Required
Length of Pipeline
Size of Compressor Facilities
Pipeline & Compressor Investment Required
Delivered Cost of CO_2

Once the supplier has determined these elements he can then provide to the producer a viable estimate of the price required for the CO_2.

This development process does not happen overnight. PanCanadian spent six years studying and developing a model to determine the economic viability of a CO_2 miscible flood at Weyburn. Discussions between DGC and PanCanadian first began in 1992. PanCanadian initial CO_2 demand forecast was for 150 MMSCF/D. After numerous model runs and changes over several years they were finally able to zero in on a firm demand forecast of 95 MMSCF/D of CO_2. Admittedly the PanCanadain Weyburn field is a large project, but without performing the necessary modeling to refine their field development approach, they would have invested significantly more capital than necessary and contracted for considerably more CO_2 than needed. Both factors would have contributed to higher project costs and could have resulted in a decision not to proceed with the project. It is only with good data and representative field modeling that both the oil producer and the CO_2 supplier can work together to make the project an economic success.

Status of DGC's Williston Basin Pipeline

Today much of the planning for the main pipeline has been completed and we are now in the final design stages. The project team has consisted of:

Gulf Interstate Engineering

- Pipeline Design & Engineering

- Compressor Facility design & Engineering
- Construction Management

ENSR

- Environmental Studies
- Environmental Permits

Coates Field Services

- Pipeline ROW Abstracts & Options
- Pipeline Acquisition

Together this team has supplied all of the technical information required to acquire the permits from the State of North Dakota, the province of Saskatchewan, International Boundary Commission, United States and Canadian federal regulatory agencies. The 204.5 mile pipeline ROW required purchases from 358 private land owners as well as state, provincial and federal agencies. I am pleased to report that the following milestones have been accomplished.

February 12, 1998 - Received Approval from the International Boundary Commission

February 24, 1998 - ND PSC accepted Pipeline Route Permit Application as complete

March 13, 1998 - Board Approval to purchase compressor trains

March 31, 1998 - All private ROW parcels purchased

April 15, 1998 - 204.5 miles of pipe (14" & 12" diameter) ordered

April 15 & 16, 1998 - ND PSC public hearings were held in North Dakota

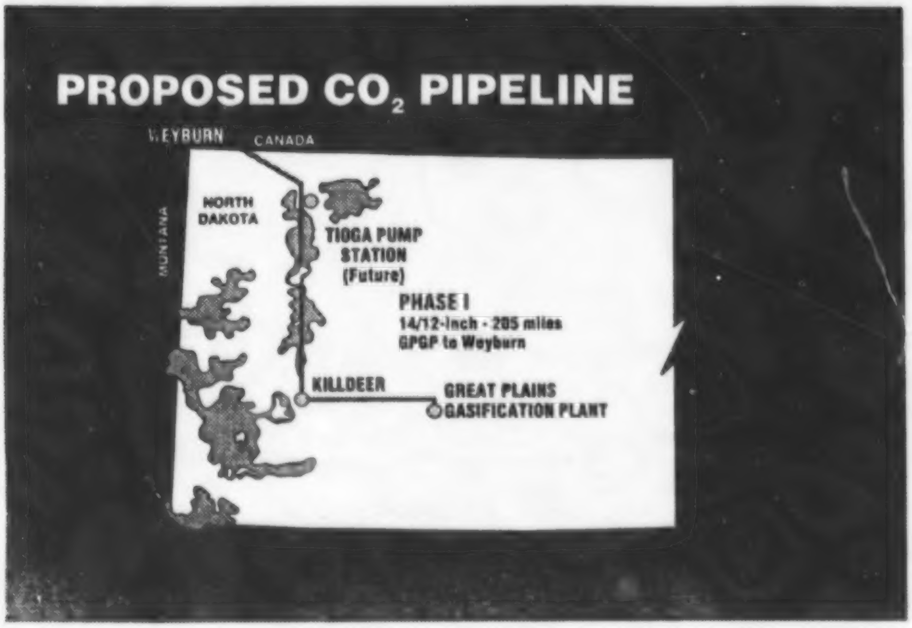
May 4, 1998 - Canadian National Energy Board public hearing

As indicated earlier, Gulf Interstate Engineering was selected as the primary engineering contractor for the project and is responsible for designing the entire gas handling and compression plant facilities as well as the pipeline from Beulah to Weyburn, i.e. "from start to finish".

The initial gas handling and compression facilities at the plant near Beulah will consist of two compressor trains, each capable of handling 55 MMSCF/D of CO_2. DGC has elected to use two multi-staged integrally geared centrifugal compressors. (Figure 4) Each compressor will have six stages which will take the CO_2 from a pressure of 16 psia to a discharge pressure of 2500 psia. The pipeline will consist of 116.5 miles of 14 inch diameter pipe to a point just north of Lake Sakakawea and 88 miles of 12 inch diameter pipe. Construction is scheduled to begin early in 1999 and be completed by the start of winter of 1999. (Figure 5)

DGC continues to work with several oil producers who have expressed an interest in acquiring a supply of CO_2. All of these companies are still in the reservoir modeling stage and have not been able to provide DGC with a firm volume and demand forecast which we require before we can under take our engineering studies to determine what the price will be for CO_2 delivered to their respective field. With the present design for the main pipeline and two initial compressor stations, DGC will only have excess capacity for about 15 MMSCF/D. Demand requirements above this quantity will require the installation of a third compressor train and possibly a booster pump station, depending on the location and quantity of the new demand. The requirement for additional capacity means that DGC will have to complete additional compressor load studies and acquire additional pipeline ROW . This takes time and it is important for oil producers to initiate discussions with DGC at the earliest possible stage in their project planning if they expect to have CO_2 available when they want to start field injection. All CO_2 sales are being undertaken under long term contracts so that DGC can be sure of adequate supplies to meet the demands of the oil producers. At this time DGC does not expect to offer CO_2 on a spot or interruptible basis.

DGC and PanCanadian are working together to insure that the project comes on line as projected. Both companies are quite excited about the pipeline and the significant benefits it will bring to them. DGC is now poised to continue working with other Williston Basin oil producers so that they can be in a position to benefit from the available supply of CO_2. Its now up to you, the Williston Basin oil producers, to tell us where the next lateral and pipeline delivery point should be (Figure 6).



PROPOSED CO_2 PIPELINE

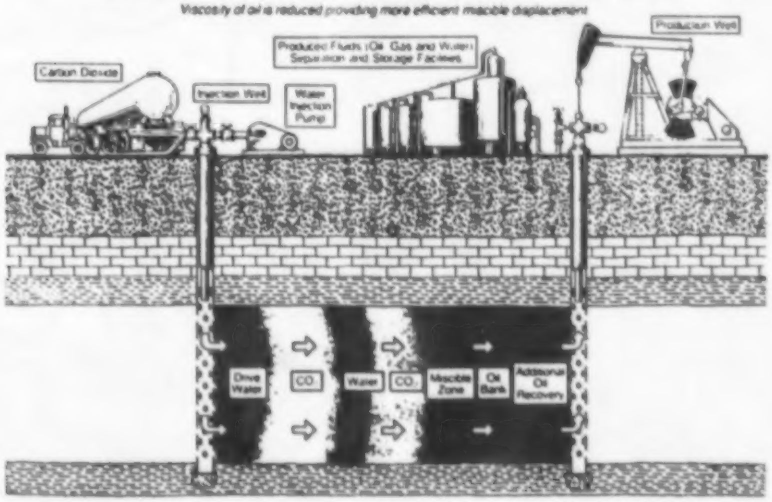
WEYBURN
CANADA
NORTH DAKOTA
MONTANA
TIOGA PUMP STATION (Future)
PHASE I
14/12-Inch - 205 miles
GPGP to Weyburn
KILLDEER
GREAT PLAINS GASIFICATION PLANT

FIGURE 1

CARBON DIOXIDE FLOODING

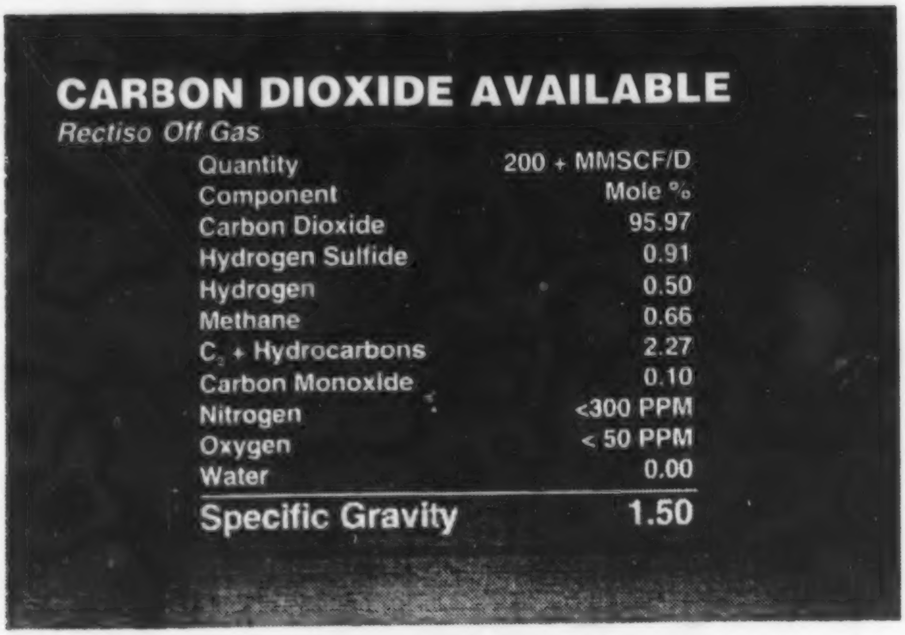
This method is a miscible displacement process applicable to many reservoirs. A CO_2 slug followed by alternate water and CO_2 injections (WAG) is usually the most feasible method.

Viscosity of oil is reduced providing more efficient miscible displacement



NIPER
Carbon Dioxide
Injection Well
Water Injection Pump
Produced Fluids (Oil, Gas and Water) Separation and Storage Facilities
Production Well
Drive Water
CO2
Water
CO2
Miscible Zone
Oil Bank
Additional Oil Recovery

FIGURE 2



CARBON DIOXIDE AVAILABLE

Rectiso Off Gas

Quantity	200 + MMSCF/D
Component	Mole %
Carbon Dioxide	95.97
Hydrogen Sulfide	0.91
Hydrogen	0.50
Methane	0.66
C_2 + Hydrocarbons	2.27
Carbon Monoxide	0.10
Nitrogen	<300 PPM
Oxygen	< 50 PPM
Water	0.00
Specific Gravity	**1.50**

FIGURE 3

Integrally Geared Centrifugal Compressor

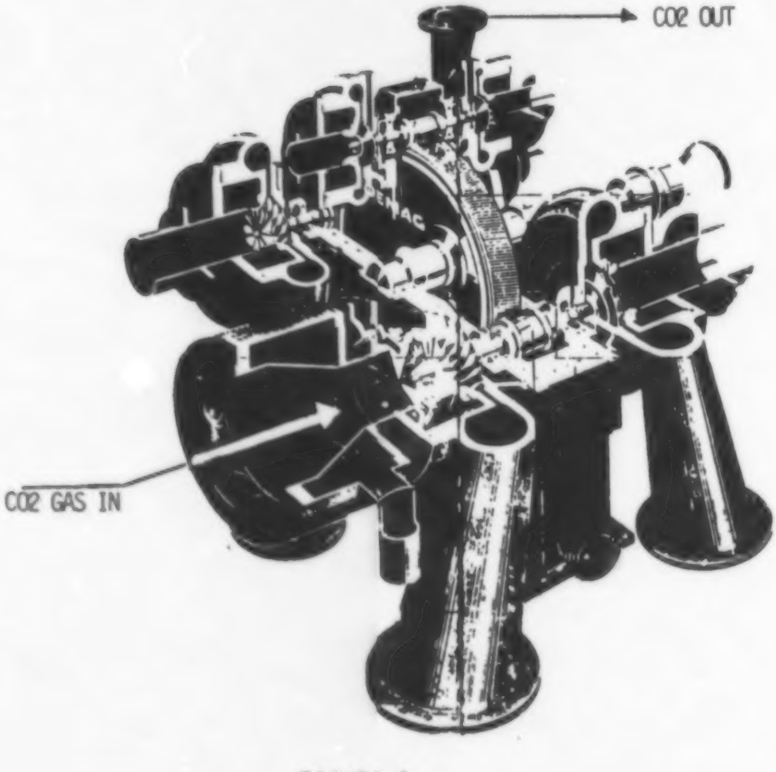
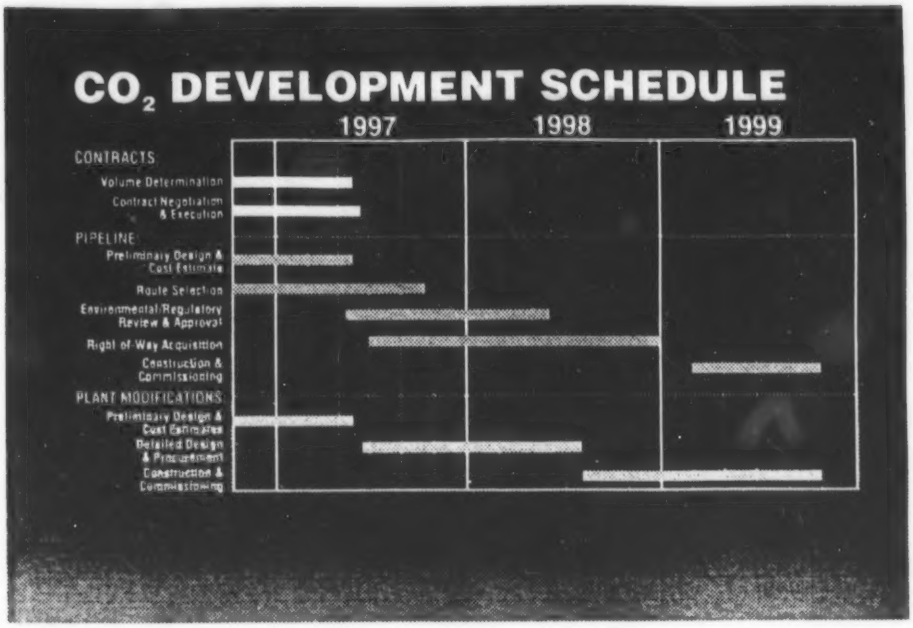
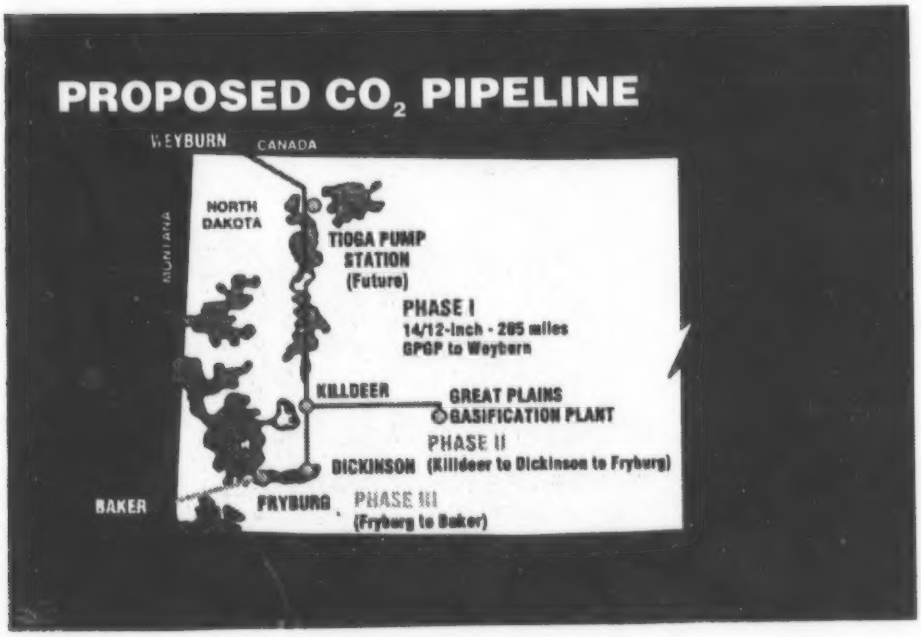


FIGURE 4



CO$_2$ DEVELOPMENT SCHEDULE

FIGURE 5



PROPOSED CO$_2$ PIPELINE

WEYBURN
CANADA
NORTH DAKOTA
MONTANA
TIOGA PUMP STATION (Future)
PHASE I
14/12-inch - 205 miles
GPGP to Weyburn
KILLDEER
GREAT PLAINS GASIFICATION PLANT
PHASE II
DICKINSON
(Killdeer to Dickinson to Fryburg)
BAKER
FRYBURG
PHASE III
(Fryburg to Baker)

FIGURE 6

G

CO2 Injection in Light and Medium Oil Reservoirs

Sam Huang
Saskatchewan Research Council

CO_2 Injection in Light and Medium Oil Reservoirs

Sam Huang
Saskatchewan Research Council

Sixth International Williston Basin
Horizontal Well Workshop

May 3–5, 1998
Bismarck, North Dakota

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Recovery Mechanisms of CO_2 Flooding

- Oil viscosity reduction
- Oil swelling
- Vaporization of oil (CO_2 extraction)
- Interfacial tension reduction
- Miscibility effects

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Background

- Saskatchewan's LMO reserves ~1.7 billion m^3
- Most reservoirs at economic limit
- EOR process essential
- CO_2 flood has strong potential for application
  - ✓ can recover up to 25% additional IOIP
  - ✓ will triple existing reserves
  - ✓ extend producing life by over 20 years
- Similar potential for Alberta LMO reservoirs
- 61 active CO_2 field projects in U.S.

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CO$_2$ Flood Field Projects in Canada

- Joffre Viking Field (Alberta)
- Midale (Saskatchewan)
- Weyburn (Saskatchewan)
    - Expected to begin late 1999
    - Largest CO$_2$ EOR venture in Canada ($1.1 billion)
    - SRC contributed significantly to design

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Benefits of CO_2 Injection

- Increased reserves and field life
- Improved sweep and recovery efficiency
- Prolonged return on investment
- Flexibility of implementation
- Environmental benefits through storing of greenhouse gases

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OVERALL PROGRAM GOAL

To help petroleum industry clients with holdings in LMO reservoirs to increase their oil recovery efficiency, reserves, and production.

How Do We Do This?

By providing experimental data to screen reservoirs for CO_2 or hydrocarbon flooding, and to optimize field operating procedures.

Project Participants

ADOE
Amoco Canada Petroleum
CANMET
Gulf Canada Resources
Husky Oil
Marathon Oil
Mobil Oil Canada
Murphy Oil
Norcen Energy Resources
PanCanadian Petroleum
Sceptre Resources (CNRL)
Shell Canada
Talisman Energy
Texaco Canada
Vista Energy
Wascana Energy (CanOxy Petroleum)

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Technical Studies

- Screen reservoirs for suitability
- Provide reliable data:
    - to optimize field operating procedures
    - to predict recovery
- Tailor injection strategy to client's reservoir
- Solve production problems
- Study effect of reservoir depletion and MMP on oil recovery

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Technical Questions

- Minimum miscibility pressure (MMP)
- Impurities in CO_2
- Solids precipitation
- CO_2 injection strategy
- Permeability contrast in reservoirs
- Wettability change and acidic effect
- Water blocking of oil
- Viscous instabilities, gravity segregation
- Heterogeneity

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Approach

- Measure PVT properties of oil–solvent system
- Determine oil–solvent system MMP
- Quantify asphaltene flocculation/ precipitation
- Study oil recovery efficiency in corefloods
- Conduct numerical simulation

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Reservoirs Studied

In Southeast Saskatchewan

- **3 Weyburn oils** (29–36° API)
  - PanCanadian and Wascana Energy
- **3 Steelman oils** (35–40° API)
  - Sceptre Resources and Wascana Energy
  - CNRL
- **Alameda** (41° API)
  - Talisman Energy

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Task 1: PVT Studies

Purpose: To determine specific recovery mechanisms and to provide data for numerical simulation

Method: Reconstitute reservoir fluid

Study phase behaviour of reservoir fluid/CO_2 mixtures

Determine PVT properties of formation brine/CO_2 mixtures

Results: Demonstrated oil viscosity reduction and swelling with pure/impure CO_2, potential of miscible flooding

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Task 2: Asphaltene Quantification

Purpose: To determine effect of CO_2 injection on asphaltene flocculation/precipitation

Effects Studied:
- CO_2 concentration
- Presence of formation brine
- Impurities in CO_2
- Operating pressure
- Oil properties
- Variation in matrix permeability

Results: CO_2 concentration the only important parameter

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Task 3: MMP Determination

Purpose: To screen reservoirs and select operating pressure

Solvents Studied:
CO_2, impure CO_2 (CH_4, N_2, H_2)
CO_2–ethane & CO_2–propane mixtures
CO_2–Steelman gas mixtures

Method:
Rising bubble apparatus
Slim tube apparatus
Correlation prediction

Results: CO_2 miscible flooding found promising

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Task 4: Coreflood Studies

Purpose: To obtain oil recovery potential from linear coreflood tests

Effects Studied:
Pressure in near-miscible region
Preserved and cleaned cores
Permeability contrast of Marly-Vuggy zones
CO_2 diffusion mechanism

Results: Microscopic sweep efficiency improved with pressure in near-miscible region

CO_2 flooding can provide high recovery

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Our Related Publications

1. Srivastava, R.K. and Huang S.S., *Laboratory Investigation of Weyburn* CO_2 *Miscible Flooding*, CIM Paper 97-154 presented at 7th Saskatchewan Petroleum Conference, Regina, October 19–22, 1997.
2. Srivastava, R.K. and Huang, S.S., *Asphaltene Deposition During* CO_2 *Miscible Flooding: A Laboratory Assessment*, SPE paper 37468 presented at 1997 Production Operations Symposium, Oklahoma City, March 9–12, 1997.
3. Srivastava, R.K. and Huang, S.S., *Miscible Flooding in Light Oil Reservoirs—A Post-Waterflood Option*, an invited paper presented at 4th International Williston Basin Horizontal Well Workshop, Bismarck, ND, May 5–7, 1996.
4. Srivastava, R.K. and Huang, S.S., *Technical Feasibility of* CO_2 *Flooding in Weyburn Reservoir—A Laboratory Investigation*, CIM paper 95-119 presented at 6th Saskatchewan Petroleum Conference, Regina, Oct. 16–18, 1995.

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5. Srivastava, R.K., Huang, S.S., Dyer, S.B., and Mourits, F.M., *Quantification of Asphaltene Flocculation in Saskatchewan Light and Medium Reservoirs*, JCPT, 31-42, Oct. 1995.

6. Srivastava, R.K., Huang, S.S., Dyer, S.B., and Mourits, F.M., *A Comparison of Minimum Miscibility Pressure Determinations for Weyburn CO_2 Solvent Design*, paper CIM 94-50 presented at 45th Annual Technical Meeting of the Petroleum Society of CIM, Calgary, June 12–15, 1994.

7. Huang, S.S., de Wit, P., Srivastava, R.K., and Jha, K.N., *A Laboratory Miscible Displacement Study for the Recovery of Saskatchewan's Crude Oil*, JCPT, 43-51, April 1994.

8. Huang, S.S. and Dyer, S.B., *Miscible Displacement in the Weyburn Reservoir—A Laboratory Study*, JCPT, 42-52, Sept. 1993.

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Multiclient Program Current Phase

September 1996–August 2000

Focus of proposed work shifted to immiscible or near-miscible injection

Year Two start date: September 1997

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Approach

Release reservoir solution gas which reduces CO_2 MMP and can make near-miscible operation possible

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Reservoir Studied for 1997/98

In Southeast Saskatchewan

- ▸ Rosebank (Frobisher-Alida beds)
  - Wascana Energy
  - 39°API oil gravity
  - Active bottomwater
  - Operating pressure ≈ 10 MPa (immiscible CO_2 displacement)
  - Hydrocarbons (e.g., C_2H_6) injection option

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Task Areas For 1997/98

▸ PVT Studies	(Task 1)
▸ Rising Bubble Studies	(Task 2)
▸ Coreflood Studies	(Task 3)
▸ Numerical Simulations	(Task 4)

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One-On-One Project

Preliminary Assessment of CO_2 Flooding Potential for Light Oil Reservoirs

Goal: To provide companies with a fast, inexpensive, and reservoir-specific assessment of suitability of CO_2 injection for their light oil holdings

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Task 1 - PVT Studies

- Collect separator oil and separator gas samples from suitable location of reservoir
- Characterize dead oil and analyze separator gas
- Reconstitute reservoir fluid
- Determine PVT properties of
    - reservoir fluid
    - reservoir fluid and CO_2 mixtures

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- These PVT properties include
  - bubblepoint pressure
  - gas–oil ratio
  - CO_2 solubility
  - viscosity as function of pressure
  - density as function of pressure
  - formation volume factor
  - swelling factor

Purpose: Provide input data for numerical simulations

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Task 2 - Rising Bubble Studies

- Determine CO_2 MMP for reservoir fluid and partially flashed reservoir fluids

Purpose: Determine suitable operating pressure for reservoir from MMP measurement

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Task 3 - Coreflood Studies

- Conduct two tertiary CO_2 slug tests with reservoir fluid at T_{res} and suitable reservoir operating pressures (one at CO_2 MMP and one below CO_2 MMP)
  - use suitable reservoir core material
  - saturate core with reservoir fluid at operating pressure
  - conduct initial waterflood until oil production becomes negligible

- inject CO_2 slug until oil production almost ceases
- follow by extended waterflood and blowdown
- determine endpoint relative permeability values at each stage of test

Purpose: (i) Determine oil recovery behaviour at each stage of test

(ii) Provide endpoint relative permeability data for numerical simulations

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H

Sidetracking in a Single Trip

***Greg Miller**
Charles Dewey
James Saylor
Smith Drilling and Completions

SPE International
Society of Petroleum Engineers

SPE 37665

Sidetracking in a Single Trip

Greg Miller, Charles Dewey, James Saylor - Smith International Inc.

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Abstract

Historically, sidetracking through existing casing requires multiple trips to effectively mill a useable window for the next directional drilling assembly. The number of trips needed depends upon the sidetracking tools capability and performance and a comfort level of the drilling engineer in charge.

This paper presents a true one-trip system for sidetracking operations. The paper will discuss design criteria, engineering analysis and validation of the design by detailed test data from field tests including photographs of actual window profiles filmed by a downhole video camera.

The objective of the one-trip system is to accomplish the following seven steps in a single trip: (1) run assembly; (2) orient whipface (with MWD); (3) set (hydraulically) whip-stock assembly; (4) separate the mill from the whip-stock; (5) mill window; (6) drill rat hole; (7) pull out of hole. The result is a full-size window with a minimum of milling time and a full-size rat hole for a directional drilling assembly.

The paper will discuss the technical innovation incorporated in the four major components of the system, namely: (1) flow switch, operationally manipulated by pump pressure, providing on/off mode for flow required for MWD orientation, circulation and anchor setting; (2) running tool, to hydraulically set the integral packer and anchor; (3) milling tool, a 3-in-1 mill, each with different objectives and dressed with pre-formed and crushed carbide and finally; (4) the whip-stock which includes a multi-ramp design to guide the mill effectively and expediently (**Fig. 1**). Also discussed will be contributions made by computer programs for bottom hole assembly and hydraulic analysis of the one-trip sidetracking system.

Introduction

It is apparent that one of the major problems in sidetracking casing is achieving the initial cut into the casing. Producing this cut out is normally done using the starter mill. Since the purpose is to achieve the sidetrack in one trip, the use of a starter mill was not an option. Typically, the starter mill has an extension below the milling portion that is used to push the cutting area off the whipface and into the casing wall. The next mill into the hole then picks up at the cut out, and continues milling the window. The mill used in a one trip system must be able to efficiently cut out of the casing as well as mill the rest of the window and drill the desired rat hole. Other systems may use a wedge, ramp, or block to initiate cut-out while protecting the whipface from the mill. The ramp device may be configured in any number of ways, but usually has to be milled away at some point during the operation.

With the system being presented here, no such ramps are needed. The special design of the mill and the whip-stock ensure that the two components work together to achieve the sidetrack.

Design Criteria

The major design criteria was to sidetrack a wellbore in one trip in 9-5/8 inch casing. It was broken into multiple design tasks as follows:

- Make-up the one trip assembly on the rig floor with minimum time and run in the hole to desired depth.
- Orient and hydraulically set the anchor.
- Shear-off at a predetermined value.
- Create a full size window (size to be the same as the drift of the casing, 8.50 inches).
- Drill a full gage rat hole (same diameter as casing drift, 8.50 inches). The rat hole should also be allowed to be as short as possible.
- Pull the milling assembly out of the hole without resistance.
- Make-up and run the directional drilling assembly for 8.50 inch hole and drill further.
- Pull out of the hole with the directional drilling assembly.
- Retrieve the whip-stock assembly by running the retrieval tool, catching onto the assembly, pulling to release the anchor, and pulling out of the hole.

Engineering Analysis

Analysis of Casing to Mill to Whip-Stock Interaction. The following discussion explains why the one-trip mill cuts into the casing more efficiently than other mills and does not mill the whip-stock away (it is a whip-stock friendly mill).

The main obstacle to overcome in producing the initial cut into the casing is generating the required side force to get the mill through the casing wall. First, the mill is pushed back into the whipface because of its contact with the casing. As the casing is cut by the mill, the total area of steel being cut increases, until it breaks through the outside wall of the casing. This causes the mill to be pushed even harder towards the whipface. Secondly, the shaft of the mill wants to remain straight. As the shaft deflects, the force of the mill on the whip-stock increases even further. How to overcome these increasing forces as the mill progressed was the basic concern when designing the system.

In order to make the mill cut the casing more than the whip-stock itself, a mill was produced that would more aggressively attack the casing rather than the whip-stock. This meant that the mill must have a greater contact area with the whip-stock than with the casing. What this produces is a much higher contact stress on the casing than the whipface, ensuring that the casing is cut away faster than the whip-stock. To achieve this goal, a change in the mill design was required. Testing results demonstrated that a conventional square bottom mill would initially mill the whip-stock instead of the casing. Of course, this is assuming no other device is incorporated to push the mill away from the whip-stock. This is logical because initially the gage area of the mill is in contact with the casing and only the very lower corner of the mill is in contact with the face of the whip-stock. What this creates is a much higher contact stress on the whipface than on the casing, dictating that the whip-stock is severely cut into while the casing is not cut through as desired.

Initial Milling. The mill was designed with a profile that contained surfaces that more closely matched those of the surfaces on the whipface. This meant that several different surfaces had to be produced on the mill to correspond to the whip-stock surfaces. The lower most taper on the mill is aggressive to match the angle at the top of the whip-stock (**Fig. 2**). This initial angle is used to quickly force the mill into the wall of the casing and achieve cut out. There is also another very important feature that is produced by this unique mill design. The aggressive angle at the very top of the whip-stock means that it's thickness increases rapidly. This allows for sufficient room to install an attachment/break bolt through the top of the whip-stock and the bottom of the mill while maintaining a full gage lead mill. This is very important if a short full gage rat hole is desired (**Figs. 3 and 4**). The length of the full gage section of the mill is reduced so as to produce a high contact stress into the casing. This surface also closely matches the straight section of the whipface. At this point milling is straight, so side forces on the mill are less severe (**Figs. 5 and 6**). Between the full gage area and the aggressive lower taper, there is an intermediate taper that closely matches the majority of the whipface.

The whip-stock material is heat treated steel that is much harder and stronger than the casing. The casing therefore, becomes relatively more sacrificial. No hardfacing is used on the whipface, so undesirable damage to the mill is avoided.

Mid-ramp Accelerator. The mid-ramp accelerator prevents the mill from coring and reduces milling time (**Fig. 7**). Mills tend to stall when the center of the mill is on the casing wall. This occurs because of the reduction of cutting element speed (the carbide) as the center of the mill approaches the casing wall. At a whipface of 3 degrees or less, it takes a substantial amount of progress to push the center of the mill from just inside the wall of the casing to the outside edge of the casing. If the center of the mill is forced across the wall of the casing with a more aggressive angle, then less milling is done by the center. This reduces milling time while also preventing the mill from coring. If the mill cores severely enough, then milling will stop and the assembly will have to be pulled. A subsequent mill run is then needed to finish the window.

Mill Dressing. The mill dressing consists of an application of both crushed carbide as well as preformed carbide for faster, more consistent milling.

The pre-formed carbide incorporates multiple chip breakers to ensure that cuttings can be easily removed from the wellbore. If longer stringers of metal are produced by the mill, it becomes difficult to push them up hole and ultimately slows the milling and drilling process.

The crushed carbide is a stable structure not easily chipped or worn away, thus helping the mill remain full gage.

Circulation. Drilling fluid is circulated during the milling and drilling process to keep the cutting structure cool and to clean the hole. An optimum amount of circulation is desired during the milling of the casing and the drilling of the rat hole. After the anchor has been set, circulation ports in the mill are opened to provide circulation to the most needed areas.

One port is opened when the attachment/break bolt is parted. More ports are opened upon starting the milling process using breakaway caps that break when contacting the whip-stock surface during rotation. The number of ports may vary.

Validation

Two tests were performed on the system to validate the design criteria, engineering analysis, and overall tool performance.

Uncemented Casing Test. This test was performed to prove out the window cutting ability of the profiled mill and multi-ramp whipface. The casing was retrieved to examine the window profile.

A 12-1/4 inch hole was drilled to a depth of 450 feet, and 9-5/8 inch-47 lbs/ft, P110 grade casing was run into the hole. This casing was not cemented so it was secured at the surface. The system was made up and run into the hole to a depth of 380 feet. After setting the anchor, the mill was pulled off the whip-stock, breaking the attachment/break bolt. Several problems with the test set-up occurred during the milling of the window that dictated that the mill be pulled from the hole. That aside, the window was milled in 11 hours. The mill was pulled from the hole and the casing was retrieved. The mill was successful at cutting out and milling the window. The window was over 8.50 inches wide and about 12 feet in length.

Cemented Casing Test. This test was performed to reconfirm the system's performance by cutting a window, running a directional drilling assembly and then retrieving the whip-stock. This test also used 9-5/8 inch-47 lb/ft, P110 grade casing, this time cemented.

A 12-1/4 inch hole was drilled to 794 feet. The casing was run to a depth of 778 feet and cemented in place. The sidetracking system was made-up and run into the hole to a depth of 729 feet. After setting the anchor, the mill was pulled off the whip-stock. Milling of the window then began and continued until the lead mill reached the bottom of the whip-face, 5.5 hours later. The milling rate was about 2 ft/hr. Eleven feet of rat hole was then drilled in approximately 2 hours. The hole was blown dry so that a downhole video camera could be run in on wireline. The mill was pulled from the hole and the video camera run down. The camera verified that the window had been cut. A drilling assembly was made-up and run into the hole. This BHA consisted of an 8.50" bit on a full gage integral blade near bit stabilizer, made up to 6 inch drill collars. The assembly passed through the window and reached the bottom of the rat hole.

Running Procedure

The one-trip mill is picked up first and set in the slips. The running tool is picked up and made up to the top of the mill. This assembly is picked up and raised over the hole. The whip-stock anchor assembly is then picked up and lowered into the hole, leaving access to the top of the whip-stock. The running tool and one-trip mill are lowered until the lead mill is adjacent to the top of the multi-ramp whip-stock. The mill is attached to the whip-stock using the attachment/break bolt. The hydraulic connector is made-up to the bottom of the mill on one end and to a port in the whip-stock on the other end. The assembly is lowered into the hole to gain access to the top of the running tool. The system is filled with clean oil and the setting piston is installed. The flow control sub is made up to the running tool (spaced out if desired) and lowered. The remaining tubular joints are then made up as needed, with an MWD that is aligned with the face of the whip-stock.

The complete system is lowered to the setting depth. The mud pumps are started and circulation is sustained at a rate suitable for receiving feedback from the MWD. Surveys from the MWD are used to obtain the proper orientation of the whipface. Once proper orientation is achieved, the flow control valve is closed and the anchor is hydraulically set. Tension is then pulled on the drill string until the attachment/break bolt fails. This also opens a port for mud circulation, which is used for cleaning and cooling the mill and for lifting the cuttings to the surface.

The system is now ready to mill the window. While rotating with mud pumps on, the drill string is lowered until it starts to pick up weight. Light weight is used at first to allow for efficient cut out of the lead mill. As milling progresses, weight can be increased to obtain a good milling rate. Once the window is milled (**Fig. 8**) and the desired rat hole is drilled (**Fig. 9**), the mill is pulled out of the hole. The sidetracked wellbore is now ready to be entered with a full gage directional drilling assembly.

Technical Innovations

Flow Switch. The flow switch is a device that allows for circulation of fluid through the drill string for operation of the MWD without setting the anchor, if it is hydraulic set. With the information from the MWD surveys, the whipface can be properly oriented prior to setting. Flow switches can come in various forms. The shear pin device, the indexing sleeve device, etc. all contain ports that allow drilling fluid to flow from the drill string to the annulus without over pressuring the hydraulic set anchor setting mechanism. When the sleeve within these tools is activated to the closed position, the drill string can then be pressured to set the anchor.

Running Tool. The running tool is used to prevent drilling fluid from contaminating the setting mechanism of the anchor. It contains a piston that preserves clean oil below and keeps the drilling fluid above. Upon setting, the piston strokes downward until the anchor is completely set. Once the mill is pulled from the whip-stock assembly and circulation begins, the piston locates itself in a position such that drilling fluid may by-pass and be circulated through the mill.

Milling Tool. The mill incorporates three mills, all of which are full gage mills. The lead mill includes a somewhat short gage section at the top and a conical shape nose below to match with the whip-stock surface. The mill also incorporates multiple circulation ports with breakaway caps that allow full flow circulation once the attachment/break bolt is broken and milling is started. The breakaway caps are protected during the trip into the hole so that the integrity of the clean hydraulic oil system is maintained until the anchor is set.

The follow mill, spaced strategically above the lead mill incorporates a teardrop shape and is designed to further elongate the window as progress is made.

The dress mill, located above the follow mill, resembles a watermelon mill design and includes carbide dressing to smooth or dress off the window profile.

Since the lead mill is a full gage mill, it allows the drilling of a short rat hole if desired.

Whip-Stock. Unlike conventional whip-stocks, the face of the one-trip whip-stock includes multiple ramps with different tapers. A radical ramp is located at the top of the whip-stock to allow for mill hook-up and to expedite the initial engagement with the casing. The ramp is followed by a straight surface (no taper), allowing trouble-free progress of the mill assembly.

Below the straight section, a conventional low angle ramp is used to further deflect the mills toward the formation.

Finally a mid-ramp accelerator (radical departure) is included which, when the mill's center is adjacent to the casing wall, deflects the mill more expediently into the formation.

Hardmetal application was eliminated from the whipface due to heat treatment of the whip-stock.

Bottom Hole Assembly Program. This computer program was initially developed to calculate bending stresses in the bottom hole drilling assembly depending upon the hole curvature, formation characteristics and various stabilization points. The program was used effectively to optimize the locations of the three mills depending upon the resulting bending characteristics of the mill shaft and the loading of the mill connection. The program also allows for the examination of the angle building tendencies in stiff assemblies (drill collars) verses limber assemblies (drill pipe). The drill collars or drill pipe are run above the milling assembly.

When milling a window and drilling a rat hole, different BHA's can be run depending on what the next drilling assembly is supposed to achieve. Short radius drilling assemblies can use a limber milling assembly and a short rat hole. If a short radius departure is not required, a stiffer milling assembly can be used, and a longer rat hole drilled.

Hydraulics Program. The hydraulics program was originally developed for drilling tools. It calculates the pressure drop throughout the system and analyzes the standpipe pressure depending upon the flow rate and vise versa.

The one-trip system performs best with optimum flow rates during the milling and drilling operations. For this reason, the program was used to study the pressure distribution and the hole cleaning characteristics of the entire system.

It is recommended that the program be utilized on all future jobs for optimum jet sizing depending upon the rig's capability.

Conclusion

The performance during testing of the one-trip sidetracking system met all the objectives set forth before the beginning of the project. Field application of the system has begun and further refinements will occur as input is evaluated.

ONE-TRIP SIDETRACKING SYSTEM

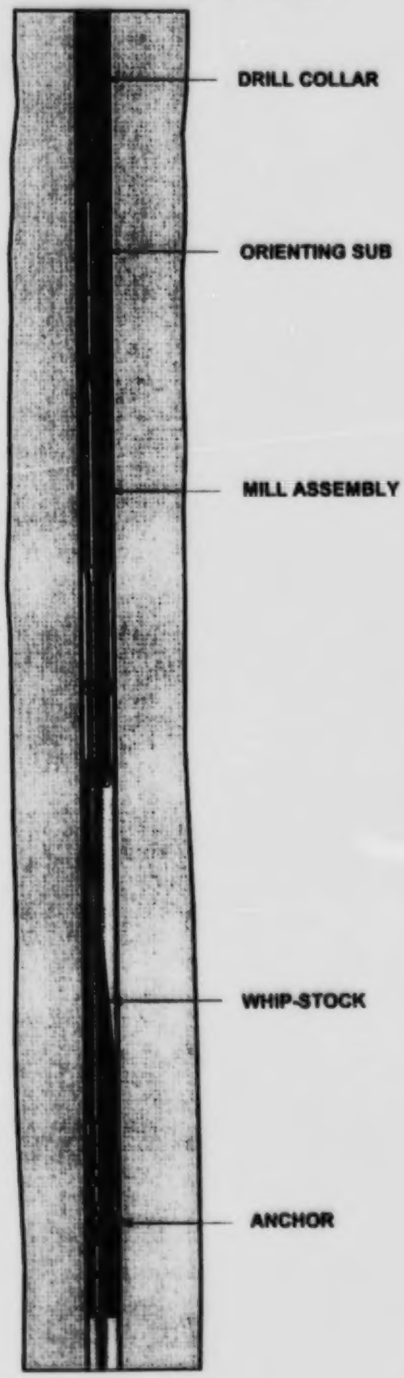

DRILL COLLAR
ORIENTING SUB
MILL ASSEMBLY
WHIP-STOCK
ANCHOR

FIGURE 1

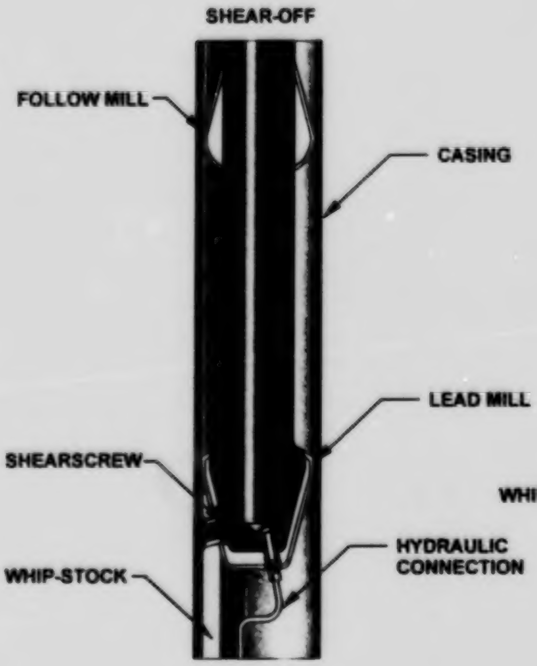

SHEAR-OFF
FOLLOW MILL
CASING
LEAD MILL
SHEARSCREW
HYDRAULIC CONNECTION
WHIP-STOCK

FIGURE 2

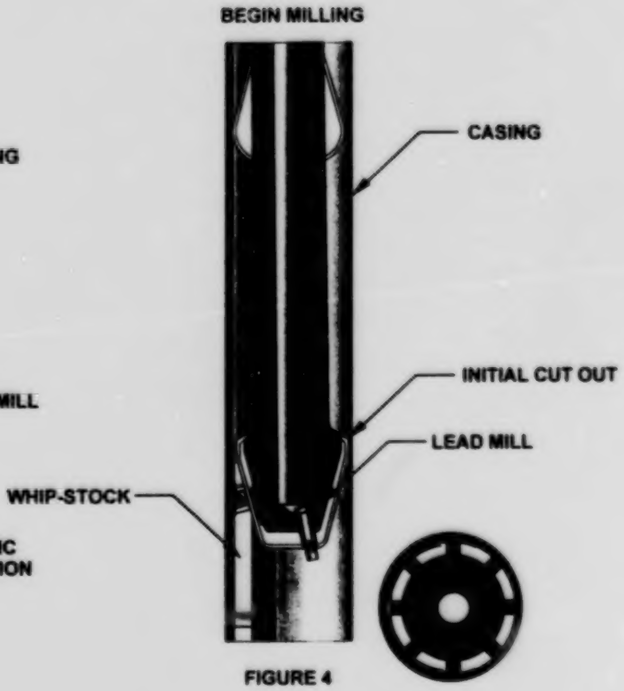

BEGIN MILLING
CASING
INITIAL CUT OUT
LEAD MILL
WHIP-STOCK

FIGURE 4

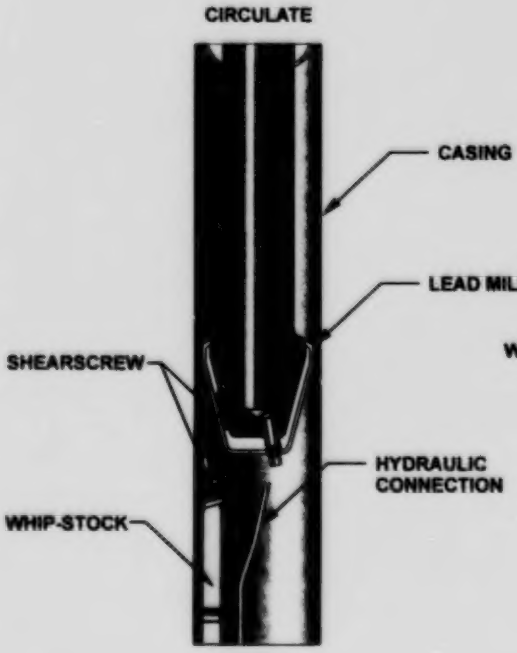

CIRCULATE
CASING
LEAD MILL
SHEARSCREW
HYDRAULIC CONNECTION
WHIP-STOCK

FIGURE 3

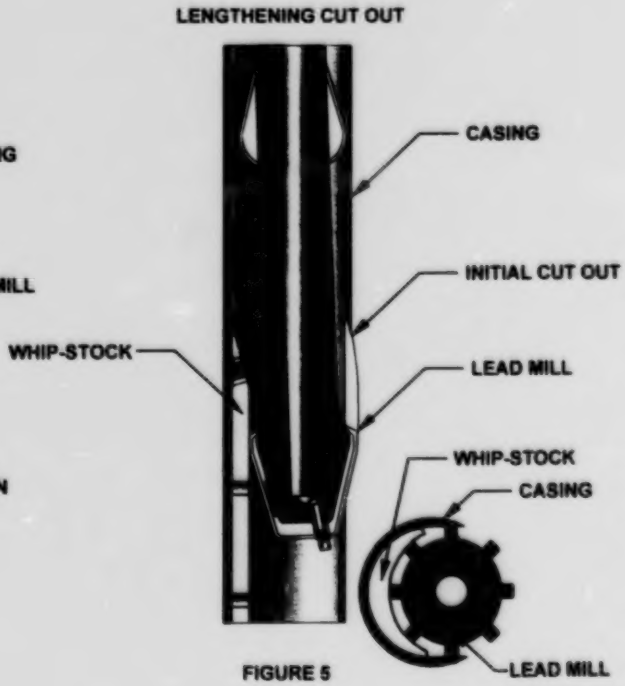

LENGTHENING CUT OUT
CASING
INITIAL CUT OUT
WHIP-STOCK
LEAD MILL
WHIP-STOCK
CASING
LEAD MILL

FIGURE 5

CONTINUE MILLING

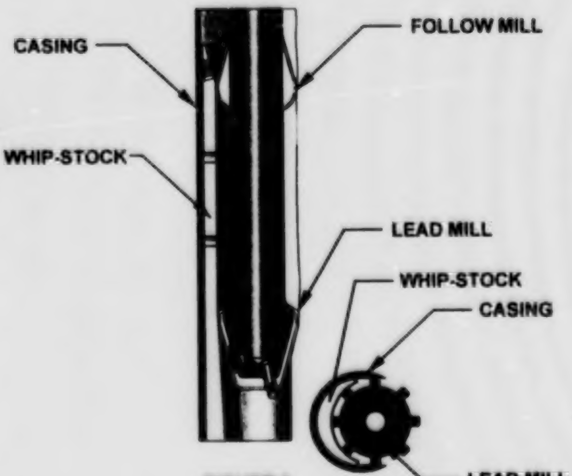

CASING
FOLLOW MILL
WHIP-STOCK
LEAD MILL
WHIP-STOCK
CASING
LEAD MILL

FIGURE 6

PUSHING ACROSS CENTER

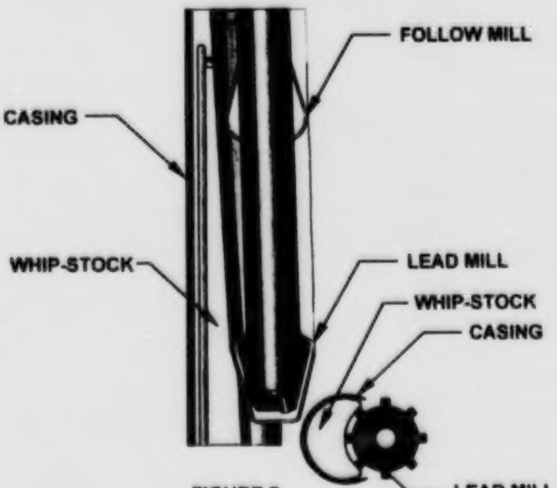

FOLLOW MILL
CASING
WHIP-STOCK
LEAD MILL
WHIP-STOCK
CASING
LEAD MILL

FIGURE 7

FINISH THE WINDOW

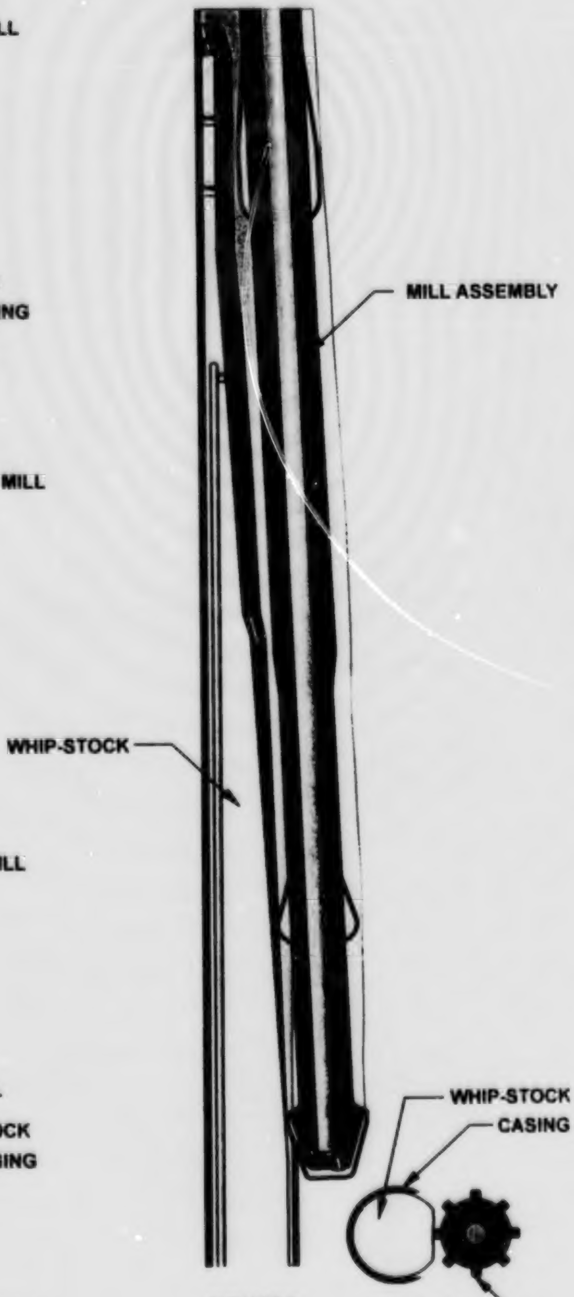
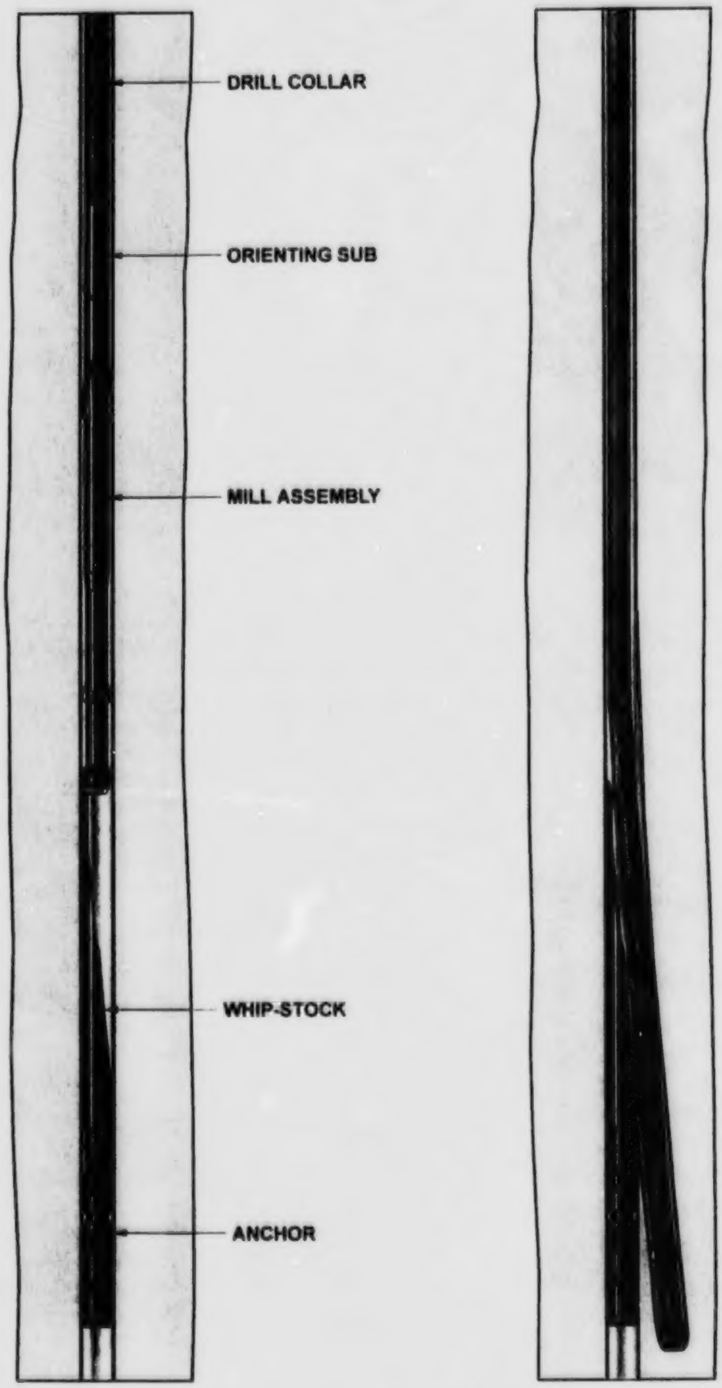

MILL ASSEMBLY
WHIP-STOCK
WHIP-STOCK
CASING
LEAD MILL

FIGURE 8

ONE-TRIP SIDETRACKING SYSTEM


DRILL COLLAR
ORIENTING SUB
MILL ASSEMBLY
WHIP-STOCK
ANCHOR

PROCEDURE

1. RUN IN HOLE
2. ORIENT WHIP-STOCK
3. SET ANCHOR
4. SHEAR-OFF
5. MILL WINDOW
6. DRILL RAT HOLE
7. PULL OUT OF HOLE

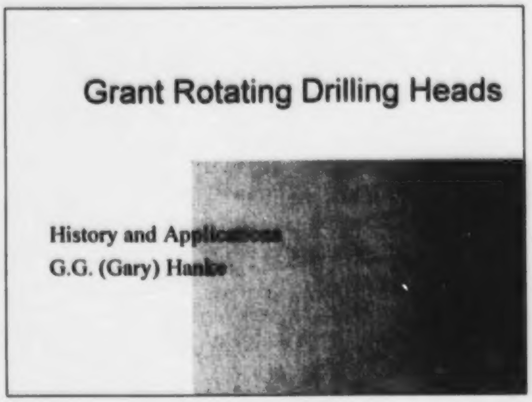
BENEFITS

- ELIMINATE STARTER MILL RUN.
- AGGRESSIVE INITIAL RAMP TO INSURE QUICK EFFICIENT CUT OUT.
- ENHANCED CUTTER TECHNOLOGY FOR CONSISTENT MILLING PERFORMANCE.
- MID WHIP RAMP TO REDUCE CORE PROBLEMS AND MILLING TIME.
- FULL GAGE MILLS TO ENSURE FULL GAGE RAT HOLE.
- ENTIRE PROCEDURE IS FINISHED IN ONE TRIP INTO THE HOLE.

FIGURE 9

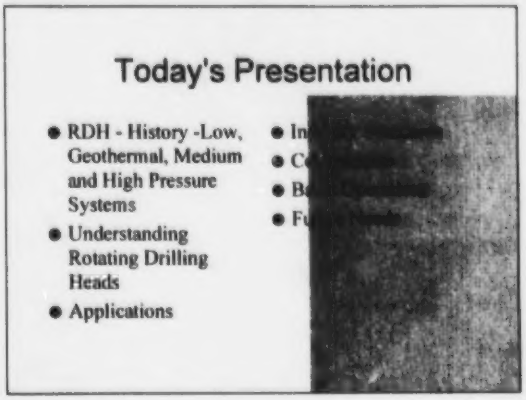
Grant Rotating Drilling Heads: History and Application

G. G. (Gary) Hanke
Smith International Canada, Ltd.



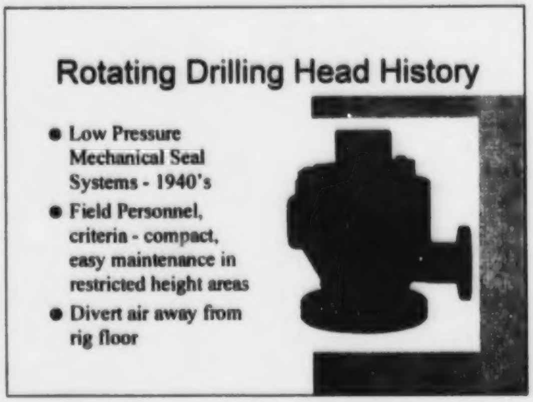
Grant Rotating Drilling Heads

History and Appl [redacted]
G.G. (Gary) Han



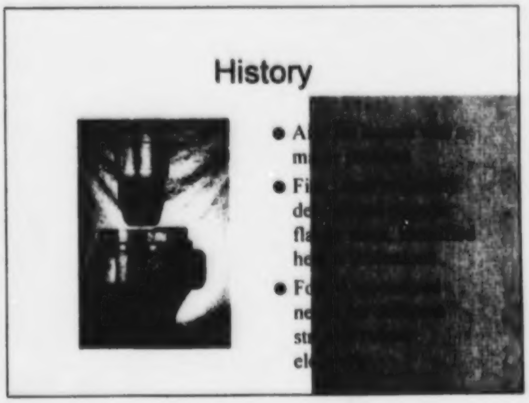
Today's Presentation

- RDH - History -Low, Geothermal, Medium and High Pressure Systems
- Understanding Rotating Drilling Heads
- Applications
- In [redacted]
- C
- B
- Fu



Rotating Drilling Head History

- Low Pressure Mechanical Seal Systems - 1940's
- Field Personnel, criteria - compact, easy maintenance in restricted height areas
- Divert air away from rig floor



History

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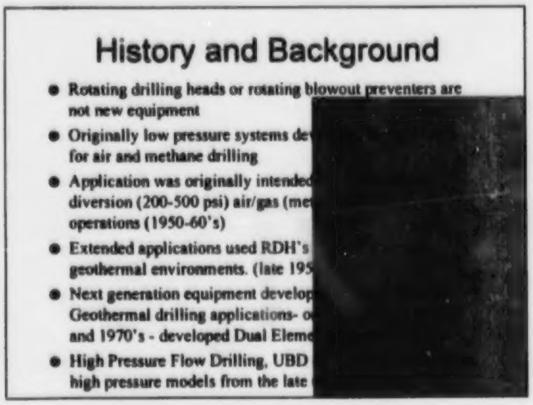
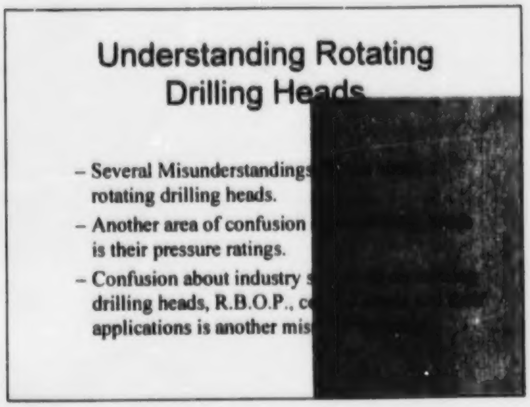


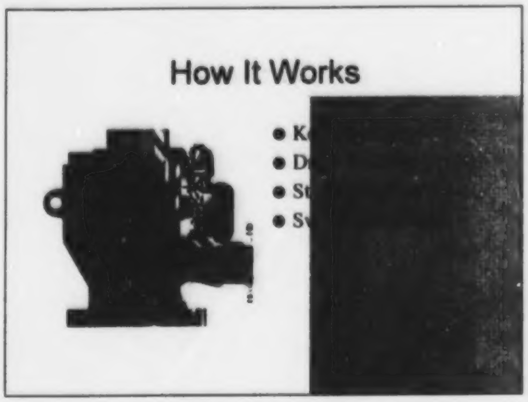
History and Background

- Rotating drilling heads or rotating blowout preventers are not new equipment
- Originally low pressure systems de [redacted]
  for air and methane drilling
- Application was originally intended
  diversion (200-500 psi) air/gas (me
  operations (1950-60's)
- Extended applications used RDH's
  geothermal environments. (late 195
- Next generation equipment develop
  Geothermal drilling applications- o
  and 1970's - developed Dual Eleme
- High Pressure Flow Drilling, UBD
  high pressure models from the late



Understanding Rotating Drilling Heads

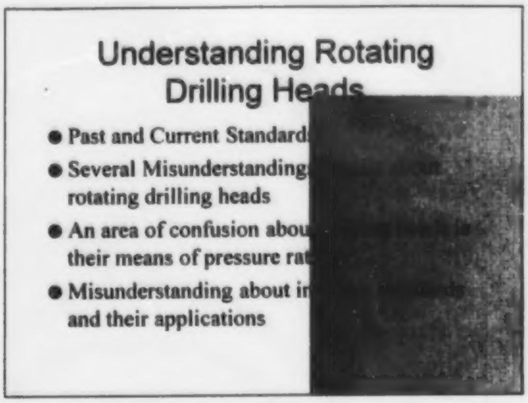
- Several Misunderstandings [redacted]
  rotating drilling heads.
- Another area of confusion
  is their pressure ratings.
- Confusion about industry s
  drilling heads, R.B.O.P., c
  applications is another mis



How It Works

- K
- D
- St
- Sv

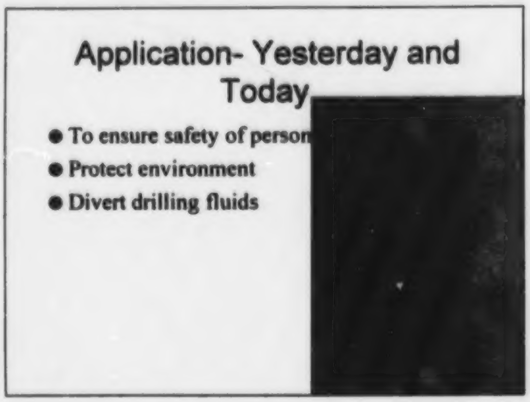
[redacted]



Understanding Rotating Drilling He

- Past and Current Standard
- Several Misunderstanding rotating drilling heads
- An area of confusion abou their means of pressure rat
- Misunderstanding about i and their applications

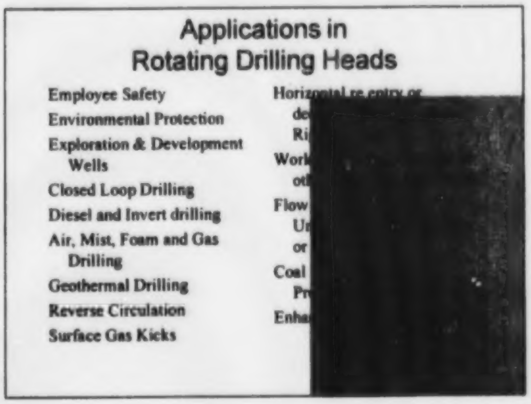
[redacted]



Application- Yesterday and Today

- To ensure safety of person
- Protect environment
- Divert drilling fluids

[redacted]



Applications in Rotating Drilling Heads

Employee Safety
Environmental Protection
Exploration & Development Wells
Closed Loop Drilling
Diesel and Invert drilling
Air, Mist, Foam and Gas Drilling
Geothermal Drilling
Reverse Circulation
Surface Gas Kicks

Horiz
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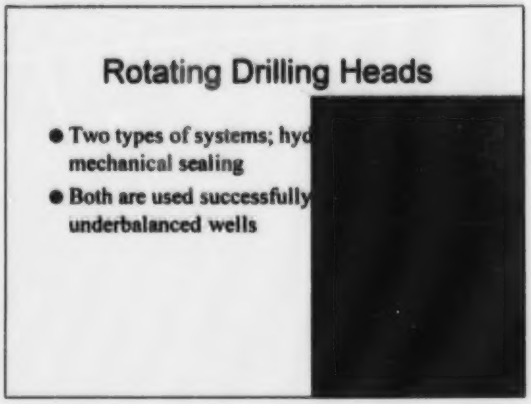
Flow
Ur
or
Coal
Pr
Enha

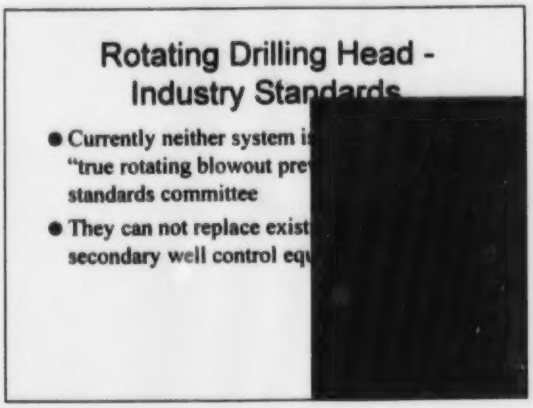
[redacted]



Rotating Drilling Heads

- Two types of systems; hyd mechanical sealing
- Both are used successfully underbalanced wells

[redacted]



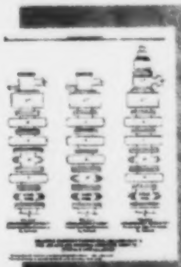
Rotating Drilling Head - Industry Stan

- Currently neither system i "true rotating blowout pre standards committee
- They can not replace exist secondary well control eq

[redacted]

Rotating Drilling Heads

- API Specification 6A or 16A
- Practice RP53- Issued May 1984 - 5 years prior to commercial usage of high pressure drilling heads- New RP53- effective March 1997



API Recommended Practice 53- Third Edition, March 1997

- Subject to manufacturer recommendations .

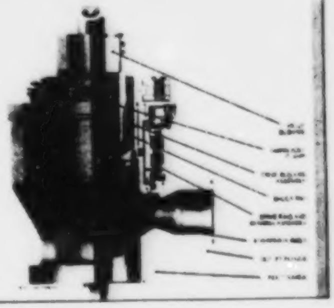
There are no clear API Guidelines for rotating heads, R.B.O.P. or other types of rotating flow control systems.

API RP 53, March 1997 Equipment & Installation 4.2.3

- Conventional annular BO [illegible] diverters, or rotating heads [illegible] diverters. The rated worki [illegible] divert and vent line(s) are [illegible] sized to permit diverting o [illegible] while minimizing wellbor [illegible]

Low Pressure System Components

- Drive Bushing
- Stripper Rubber
- Bearing Assembly
- Bowl

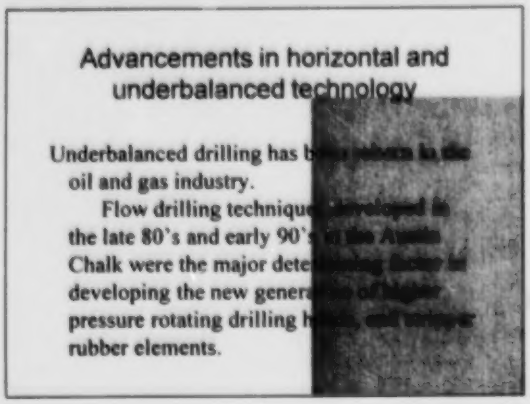


Geothermal Drilling

- Geothermal developed fir [illegible] heads
- Designed to seal on entire [illegible]
- Stationary drill collar elem [illegible]
- Rotating upper element th [illegible] kelly, drill pipe and tool jo [illegible]
- Secures a seal while tool j [illegible] are made up.

Geothermal Drilling

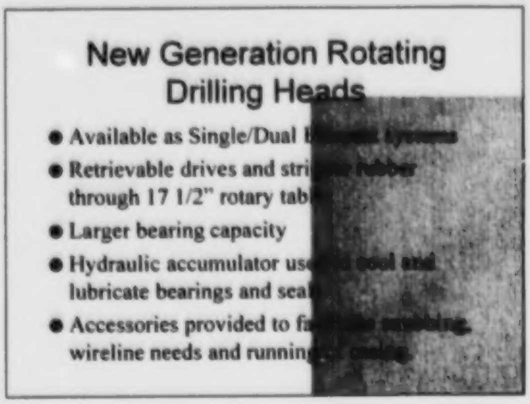
- H [illegible] 50 [illegible]
- D [illegible] up [illegible]
- W [illegible] an [illegible]
- E [illegible] fo [illegible] te [illegible]



Advancements in horizontal and underbalanced technology

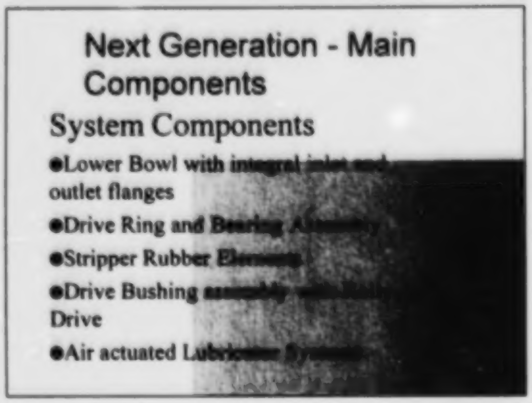
Underbalanced drilling has been proven in the oil and gas industry.

Flow drilling techniques developed in the late 80's and early 90's in the Austin Chalk were the major determining factor in developing the new generation of higher pressure rotating drilling heads, and stripper rubber elements.



New Generation Rotating Drilling Heads

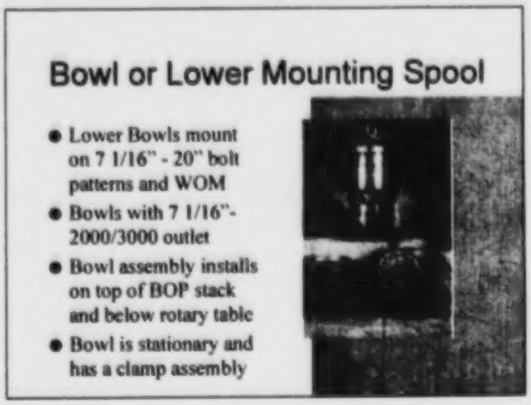
- Available as Single/Dual Element Systems
- Retrievable drives and stripper rubber through 17 1/2" rotary table
- Larger bearing capacity
- Hydraulic accumulator used to cool and lubricate bearings and seals
- Accessories provided to facilitate snubbing, wireline needs and running of casing.



Next Generation - Main Components

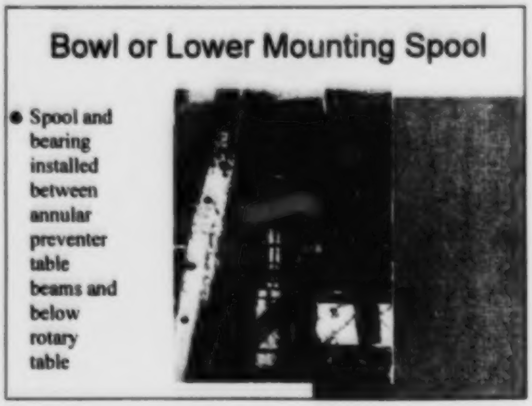
System Components

- Lower Bowl with integral inlet and outlet flanges
- Drive Ring and Bearing Assembly
- Stripper Rubber Elements
- Drive Bushing assembly with Kelly Drive
- Air actuated Lubricator Systems



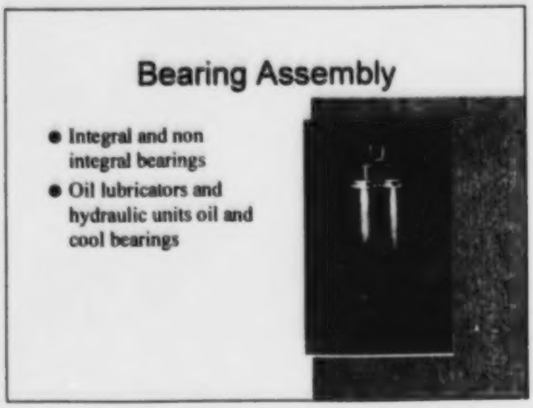
Bowl or Lower Mounting Spool

- Lower Bowls mount on 7 1/16" - 20" bolt patterns and WOM
- Bowls with 7 1/16"-2000/3000 outlet
- Bowl assembly installs on top of BOP stack and below rotary table
- Bowl is stationary and has a clamp assembly



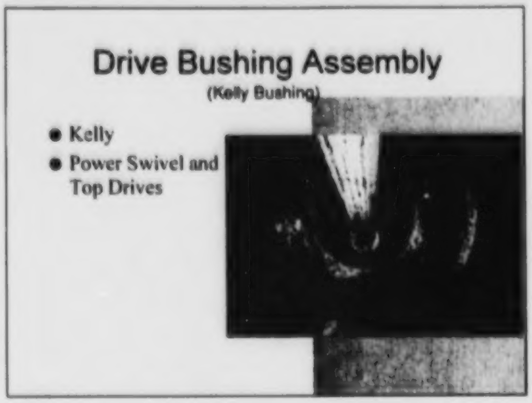
Bowl or Lower Mounting Spool

- Spool and bearing installed between annular preventer table beams and below rotary table



Bearing Assembly

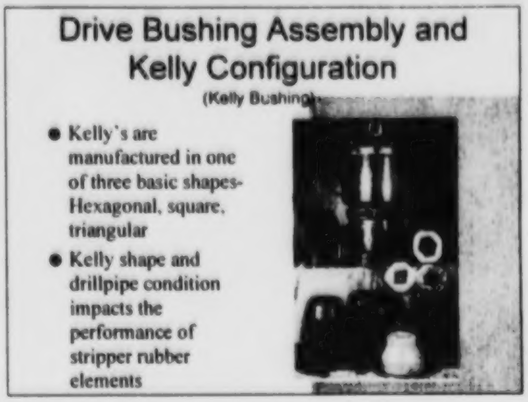
- Integral and non integral bearings
- Oil lubricators and hydraulic units oil and cool bearings



Drive Bushing Assembly

(Kelly Bushing)

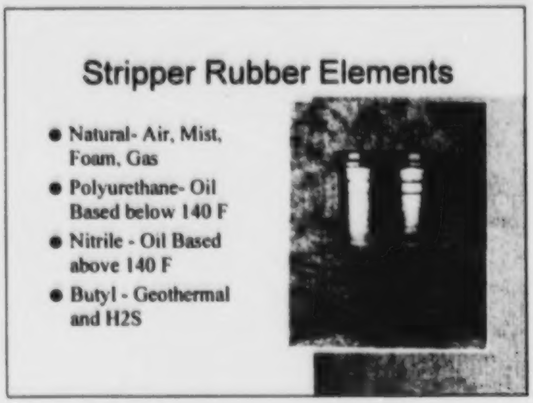
- Kelly
- Power Swivel and Top Drives



Drive Bushing Assembly and Kelly Configuration

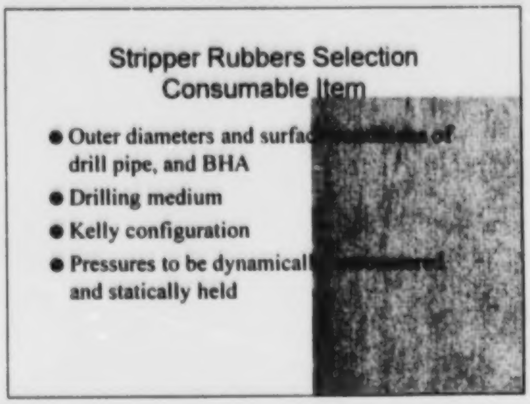
(Kelly Bushing)

- Kelly's are manufactured in one of three basic shapes- Hexagonal, square, triangular
- Kelly shape and drillpipe condition impacts the performance of stripper rubber elements



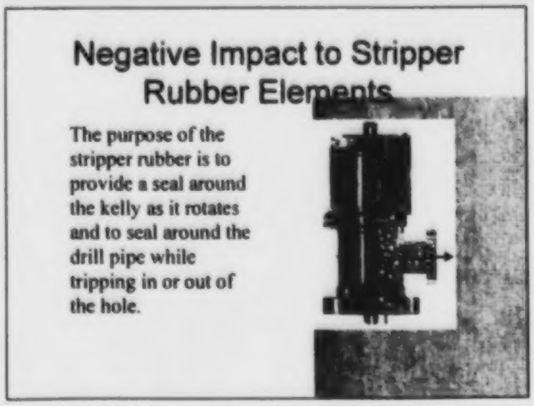
Stripper Rubber Elements

- Natural- Air, Mist, Foam, Gas
- Polyurethane- Oil Based below 140 F
- Nitrile - Oil Based above 140 F
- Butyl - Geothermal and H2S



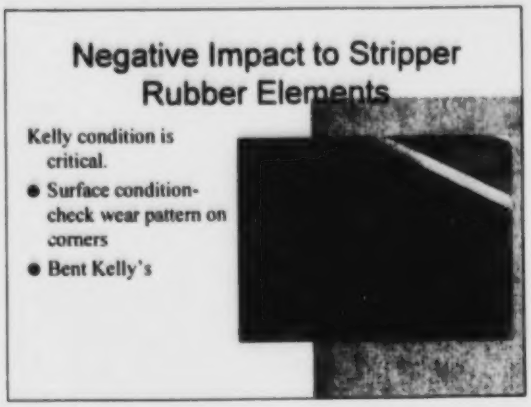
Stripper Rubbers Selection Consumable Item

- Outer diameters and surfac[illegible] of drill pipe, and BHA
- Drilling medium
- Kelly configuration
- Pressures to be dynamicall[illegible] and statically held



Negative Impact to Stripper Rubber Elements

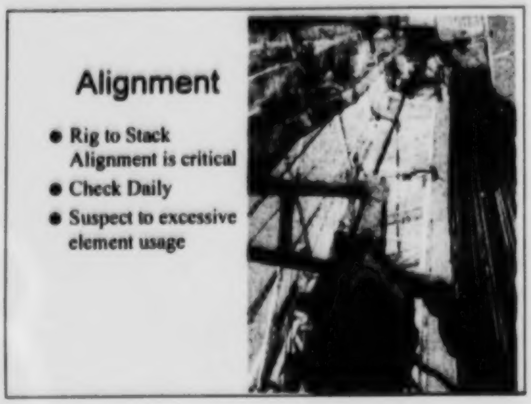
The purpose of the stripper rubber is to provide a seal around the kelly as it rotates and to seal around the drill pipe while tripping in or out of the hole.



Negative Impact to Stripper Rubber Elements

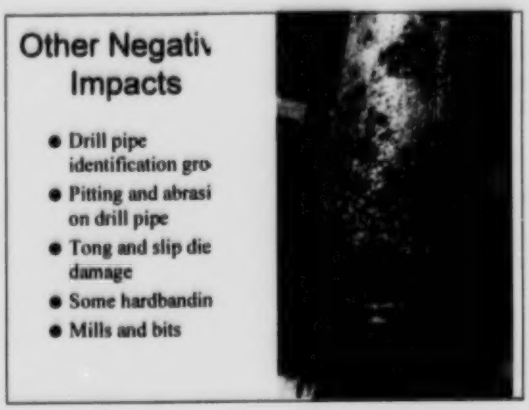
Kelly condition is critical.

- Surface condition- check wear pattern on corners
- Bent Kelly's



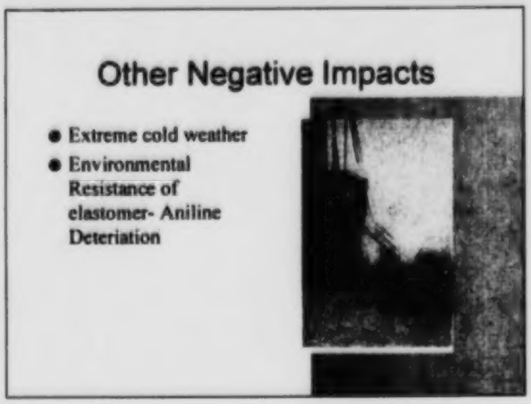
Alignment

- Rig to Stack Alignment is critical
- Check Daily
- Suspect to excessive element usage



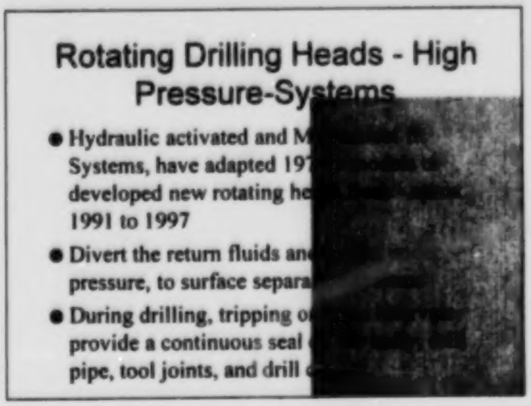
Other Negativ Impacts

- Drill pipe identification gro
- Pitting and abrasi on drill pipe
- Tong and slip die damage
- Some hardbandin
- Mills and bits



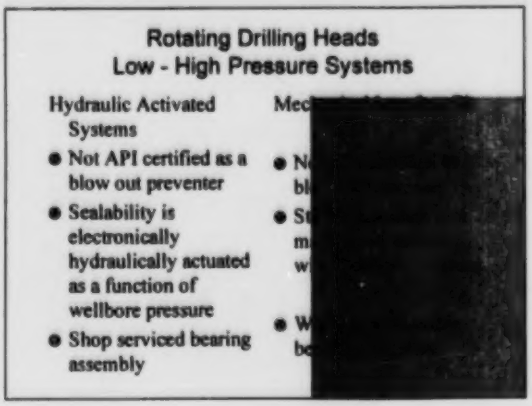
Other Negative Impacts

- Extreme cold weather
- Environmental Resistance of elastomer- Aniline Deteriation



Rotating Drilling Heads - High Pressure-Systems

- Hydraulic activated and M Systems, have adapted 197 developed new rotating he 1991 to 1997
- Divert the return fluids an pressure, to surface separa
- During drilling, tripping o provide a continuous seal pipe, tool joints, and drill



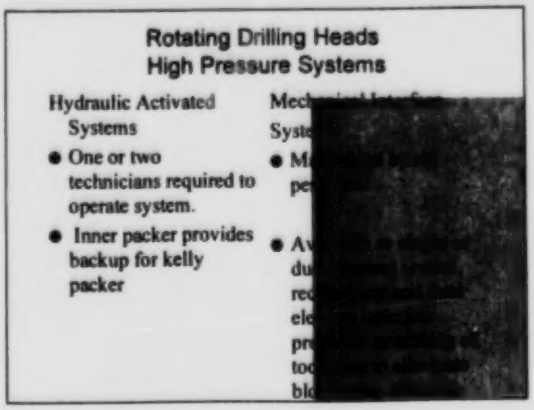
Rotating Drilling Heads
Low - High Pressure Systems

Hydraulic Activated Systems

- Not API certified as a blow out preventer
- Sealability is electronically hydraulically actuated as a function of wellbore pressure
- Shop serviced bearing assembly

Mec

- N bl
- St m w
- W be



Rotating Drilling Heads
High Pressure Systems

Hydraulic Activated Systems

- One or two technicians required to operate system.
- Inner packer provides backup for kelly packer

Mec Syst

- M pe
- A du rec ele pr to bl

Hydraulic Lubricator Systems

Hydraulic Active System

- Seal is electronically hydraulically actuated as a function of wellbore pressure and lubricates the bearing
- Usually a common oil reservoir cools bearing

Mec [illegible]
Sy [illegible]

- C [illegible] hi [illegible] lu [illegible] be [illegible] ac [illegible]
- N [illegible] to [illegible] be [illegible] pr [illegible]

Rotating Drilling Heads
High Pressure Systems

Hydraulic Activated Systems

- Large diameter housing, must be positioned below rotary table beams (requires high substructure or sunken casing bowl)
- Rubber seal or metal seal snubbing adapter(14,000-35000 kPa)

Mechanical Interface
Syst [illegible]

- N [illegible] in [illegible] be [illegible] su [illegible])
- M [illegible] sn [illegible] (3 [illegible]

Rotating Drilling Heads
High Pressure Systems

- Dynamic operations from 1500-2500 psi. range
- Static ranges 2000-5000 psi.
- Single or dual element systems
- Lower flanges from 7 1/16-2000 to 13 5/8-15000 psi.

Main Components

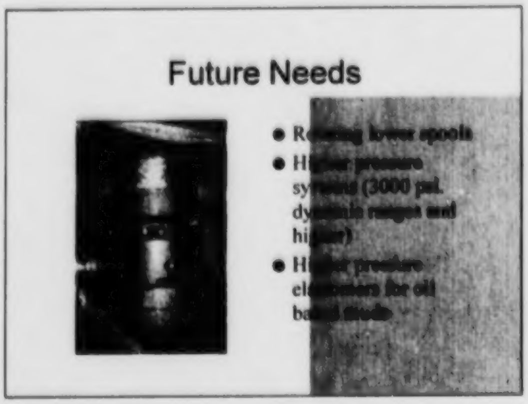
- Hydraulic Oiler Lubricato [illegible] System
- Heavy Duty Rotating Dril [illegible]

Bearing Assembly

- Contains large heavy duty [illegible] bearings
- Bearing Chamber sealed [illegible] seals against atmospheric [illegible]
- Separate high pressure se [illegible] contain wellbore pressure

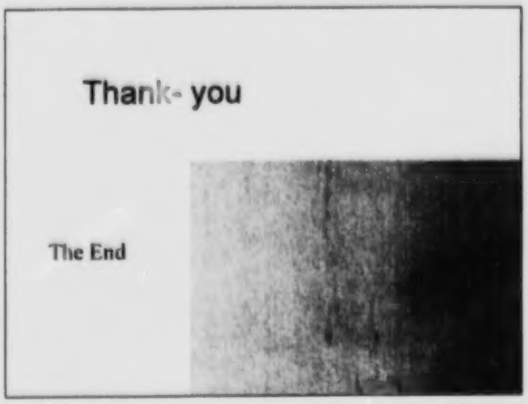
Drive Assembly and Stripper Rubber

- Elastomers available for o [illegible] geothermal drilling
- Available in single or dual [illegible]
- Combination one piece dr [illegible] stripper rubber



Future Needs

- Rotating lower spools
- Higher pressure systems (3000 psi. dynamic ranges and higher)
- Higher pressure elastomers for oil based muds



Thank- you

The End

J

Continuous Sucker Rod Reduces Costs

*Darren J. Wiltse
Michael L. Fernandez

EVI Oil Tools, COROD

THE AMERICAN OIL & GAS
REPORTER®
JANUARY 1997
The Better Business Publication Serving the Exploration / Drilling / Production Industry

Continuous Sucker Rod Reduces Costs

By Darren J. Wiltse
and Michael L. Fernandez

LOS ANGELES–Continuous, or coiled, sucker rod technology was introduced in 1965, yet its value is only beginning to be realized as advances continue to improve the technology and expand its applications.

Oil and gas producers can reduce the operational cost related to rod-pumping artificial lift systems by increasing the overall system efficiency and/or reducing maintenance costs. Continuous sucker rod enhances overall system efficiency by:

- Offering a lighter alternative, which requires less power to lift an equivalent amount of fluid;
- Falling faster, thereby increasing a reciprocating pump's effective stroke length and subsequent efficiency; and
- Reducing the overall pressure drop within a progressing cavity pump system, enabling the pump to operate more efficiently, longer, and with less power to lift an equivalent amount of fluid.

Furthermore, continuous sucker rod minimizes maintenance costs by reducing mechanical tubing wear in crooked, deviated and horizontal wells, and increases rod service life by lowering rod service stress. Also, since it has so few joints, continuous sucker rod reduces box and pin failure.

Rod-Related Failures

A typical vertical oil well that is completed with a reciprocating sucker rod pump and a steel conventional sucker rod string has three major types of sucker rod-related failures. First, tubing leaks as a result of mechanical wear between conventional sucker rod couplings and tubing constitute approximately 10 percent of the failures. Second, conventional sucker rod body breaks account for 25 percent of the failures. Finally, the largest contributor is box and pin failure, which makes up the 65 percent balance.

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MICHAEL L. FERNANDEZ *is a production engineer with Stocker Resources Inc. in Los Angeles. He is a graduate of the University of California, Los Angeles, with a B.S. in mechanical engineering, and will complete an M.B.A. from California Lutheran University in 1997. Fernandez has worked in the oil and gas industry his entire career.*

A conventional steel sucker rod string typically consists of a series of 25-foot lengths of sucker rod joined together by couplings. So, an oil well with a depth of 5,000 feet has 200 joints. Since box and pin (joint) failure is the single largest contributor to sucker rod-related failure, the obvious solution is to minimize the number of joints in a steel sucker rod string. Continuous sucker rod does just that.

Continuous sucker rod is a continuous/homogeneous length of steel with as few as two joints, regardless of length. And it has dramatically reduced the frequency of joint failure as compared to conventional steel sucker rod, thereby reducing maintenance and operational costs.

Today, there are new challenges to rod-pumping artificial lift systems. With the advent of directional and/or horizontal wells, the amount and severity of mechanical contact between tubing and sucker rod is much greater.

Conventional steel sucker rod strings promote tubing wear because of the concentrated contact load between the tubing and coupling (box and pin). Accessories like centralizers can be added to a conventional sucker rod string at an additional cost. Unfortunately, centralizers wear over time, and tubing failure then becomes inevitable.

On the other hand, continuous sucker rod makes contact with tubing over a longer length, uniformly distributing the contact load over a much greater area. This dramatically reduces the severity of mechanical wear and greatly increases the life of both the tubing and sucker rod. In fact, a 10-fold increase in tubing longevity can be realized by using continuous sucker rod. Obviously, this has a favorable impact on operational costs.

Other Advantages

When considering both reciprocating and rotary completions, continuous sucker rod also brings other advantages that contribute to operational cost reduction. These include lighter rod string, lower rod service stress and longer sucker rod life, increased pump efficiency and pump life, minimized pressure loss, use of a less expensive pump, and less power consumption at the wellhead.

Because of the unique shape of continuous sucker rod, installation is accomplished by custom-built service rigs. The rigs are automated hydraulic units, and provide several benefits, including:

- Fast rig up and rig out times (no guide lines);
- Less human handling of rod, ensuring consistent service and product performance;
- Quickest way to retrieve insert pumps (retrieval rate of 100 feet a minute);

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- Complimented with flash-butt field welding unit; and
- Inspection of continuous sucker rod string during retrieval.

Continuous sucker rod was originally made to solve an age-old problem more than 30 years ago. Today, the list of benefits and advantages continues to grow, and all equate to operational cost reduction.

There is usually a stigma associated with theories and claims, in that they sometimes differ greatly from actual results. Perhaps the best way to illustrate the advantages offered by continuous sucker rod is to examine the actual field test results from an independent oil and gas company that has applied the technology.

Field Study

In June 1996, Michael L. Fernandez of Stocker Resources Inc. in Los Angeles completed a study of oil wells in the company's Inglewood Field. Tubing wear was quite prevalent and deemed to be a costly problem. Continuous sucker rod (Corod™) was installed in a number of wells in an attempt to remedy this problem.

The study analyzes those wells in the Inglewood Field in which continuous sucker rod strings were installed to reduce hole-in-tubing related well downtime and the associated direct well pulling expenses. The study focuses on those wells in which Corod was installed before Dec. 31, 1995. Using this criterion, 15 wells were included in the study.

In order to determine the benefit obtained by installing Corod in these problematic wells, the direct well pulling expenses for each of the wells were extracted from the accounting data base for the period June 1992 through April 1996. For each well, the associated costs were extracted for the following categories:

- Subsurface repairs;
- Technical services;
- Contract rig and labor;
- Capitalized rods and tubing; and
- Trucking and hauling.

The total costs for each well were tabulated and examined both on a well-by-well and a cumulative basis. In some cases, there is difficulty in determining the exact benefit that can be directly attributed to the Corod. On many of the wells, tubing rotators and pump-off controls were also installed at some point, which help reduce direct well-related expenses themselves. In other cases, the continuous sucker rod results are obvious and very impressive.

Based on this study, it was concluded that there is a direct correlation between using Corod and a significant cost reduction in direct pulling expenses. As shown in the expense reduction summary in Table 1, the $143,000 spent installing Corod in the 15 wells paid out in 7.4 months. This is based on an average monthly Corod-related savings of $1,287 for each well each month. This correlates to a 33 percent savings over operating the well without the continuous sucker rod. The cumulative savings through April 1996 for the 15 wells was $361,000. The most outstanding results have occurred with VRU 164A and LAI1-101, which paid out in 2.5 and 4.2 months, respectively, and have each reduced expenses by more than $3,000 a month.

Figure 2 shows the direct linear correlation between these installations and reduced well pulling expenses. The higher the pre-Corod pulling expenses are, the greater the dollar benefit that can be attained through the use of continuous sucker rod. The plot shows the scatter diagram for the data plus a best-fit trend line. A statistical analysis of this trend indicates that there is a correlation coefficient of 0.7619, meaning that there is a strong relationship between the pre-Corod pulling expenses and the direct expense savings from continuous sucker rod. Using the equation which represents the trend line of savings versus pre-Corod expenses allows operators to project which wells will economically benefit by installing Corod.

Long Run Times

The question regarding the longevity of continuous sucker rod in these highly-deviated wells has been answered. So far,

TABLE 1

Corod Review
Expense Reduction Summary
Monthly Direct Well Pulling Expenses

Well	Pump Depth (feet)	Date Installed	Months Corod	Pulling Expenses w/o Failure Reducing Equipment ($/ per mo.)	Current Pulling Expense ($/ per mo.)	Pulling Expense Reduction ($/ per mo.)	Savings Attributed to Corod ($/ per mo.)	Corod % Expenses Reduc.	Corod Related Savings to Date	Corod Cost	Payout (mos.)
BC 35	1216	Apr.94	26	$2,175.00	$922.00	$1,253.00	$616.00	28.32%	$16,305.00	$5,391.00	8.8
BC 323*	1835	Apr.93	38	$1,146.00	$960.00	$186.00	$93.00	8.12%	$3,578.00	$14,744.00	158.5
LAI 81	3248	Mar.93	39	$2,725.00	$670.00	$2,055.00	$1,028.00	37.71%	$40,581.00	$11,894.00	11.6
LAI 101	3570	Feb.93	40	$3,909.00	$806.00	$3,103.00	$3,103.00	79.38%	$125,410.00	$12,924.00	4.2
LAI 136	2050	Feb.95	16	Insufficient Data	$1,821.00	Insufficient Data	Insufficient Data	InsufficientData	Insufficient Data	$8,060.00	
LAI 137	2093	Nov.94	19	$2,792.00	$2,362.00	$430.00	$215.00	7.70%	$4,177.00	$8,207.00	
LBC 4	2081	Dec.95	6	$1,792.00	$1,972.00	Insufficient Data	Insufficient Data	Insufficient Data	Insufficient Data	$8,159.00	
TVIC 46	2840	Mar.95	15	$3,686.00	$1,273.00	$2,413.00	$1,207.00	32.73%	$18,679.00	$10,588.00	8.8
TVIC 52	2803	Apr.95	14	$2,540.00	$590.00	$1,950.00	$1,950.00	76.77%	$28,201.00	$9,830.00	5.0
TVIC 57	2810	Jul.95	11	$3,300.00	$990.00	$2,310.00	$694.00	21.03%	$7,959.00	$10,492.00	15.1
TVIC 89	2509	Sept.95	9	$2,540.00	$1,225.00	$1,315.00	$658.00	25.89%	$6,200.00	$9,529.00	14.5
VIC 1 51	1344	Feb.95	16	Insufficient Data	$2,486.00	Insufficient Data	Insufficient Data	Insufficient Data	Insufficient Data	$5,801.00	
VRU 110**	1715	Aug.95	10	$1,352.00	$200.00	$1,152.00	$1,152.00	85.21%	$12,037.00	$6,988.00	6.1
VRU 164**	2237	Feb.94	28	$3,650.00	$200.00	$3,450.00	$3,450.00	94.52%	$98,012.00	$8,658.00	2.5
VRU 164	3118	Feb.94	28	Insufficient Data	$0.00	Insufficient Data	Insufficient Data	Insufficient Data	Insufficient Data	$11,478.00	
								33%	$361,139.00	$142,743.00	7.4

* Corod Cost for BC 323 Reflects Cost of Original String and Replacement String

** Estimate Of Monthly Pulling Expenses (Wells not Pulled Since Corod Was Installed) only one of the 15 Corod strings has been replaced (BC 323) after 16 months running, although the replacement string has run 22 months so far and is still in operation. The Corod string in LAI1-101 has been in operation for 40 months and is still in good condition. Others have been in the hole nearly as long, and are also still operating (39 months for LAI1-81, 28 months for VRU 164 and VRU 110, and 26 months for BC 35).

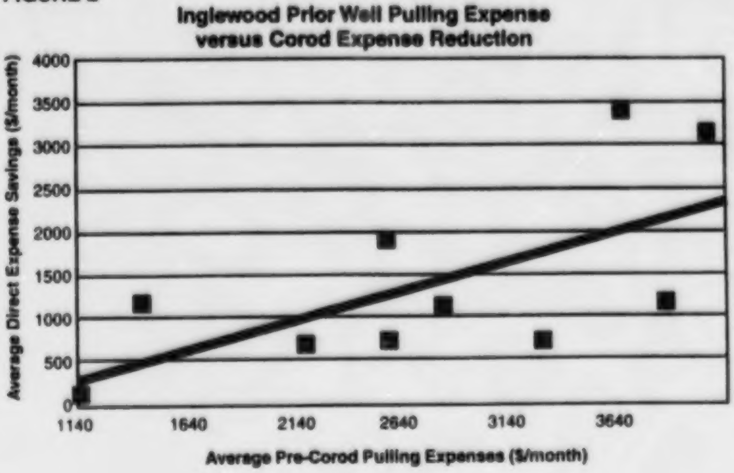
These run times indicate that the life of the Corod strings is sufficiently long to make them economic. A better indication of how long the strings are expected to last will not be known until some time in the future when more of the strings are replaced. Once the expected life of the rod string is determined, it can be better forecast when each of the rod strings will need to be replaced.

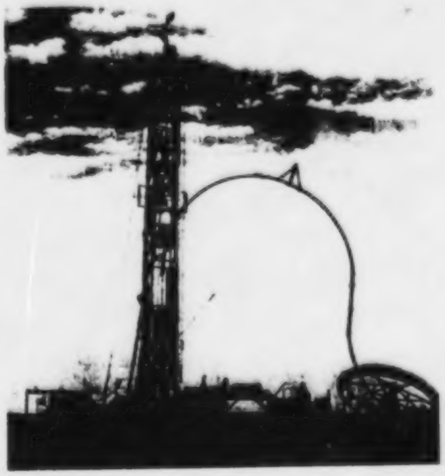
Although the results are impressive, there is a limit to which it can be economically justified. In many non-problem wells, using continuous sucker rod would not provide enough expense reduction to justify its installation. An analysis of the current average pulling expenses, the cost of the installation, and the desired payout time will have to be known for each well in order to determine whether the installation would be economically feasible.

From that information, the expected average monthly expense reduction can be applied as determined by the Stocker Resources study, and then the payout time can be determined. It is likely that many higher-expense wells will benefit from continuous sucker rod installation, but there will be diminishing returns for wells that now have low direct pulling expenses.

This study has shown that Corod has been instrumental in saving more than $350,000 to date over previous operations on these 15 wells alone. Applying the technology based on the results obtained here should continue to provide greater benefit in reducing well-related pulling expenses in those wells where it can be economically justified. ❐

FIGURE 2





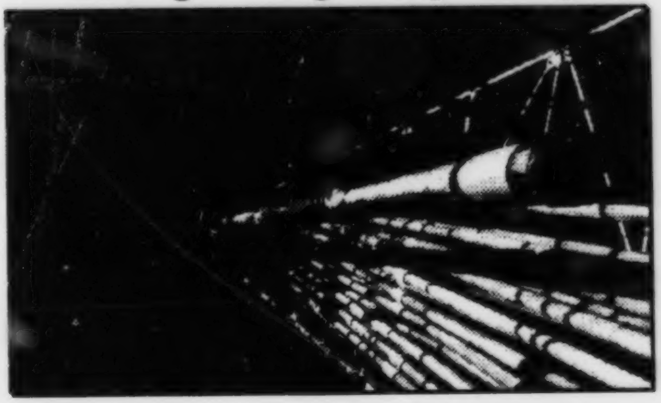
Because of the unique nature of continuous sucker rod, custom automated hydraulic units are used during installation.

K

Multi-Zone Formation Pressure Testing During a Wiper Trip

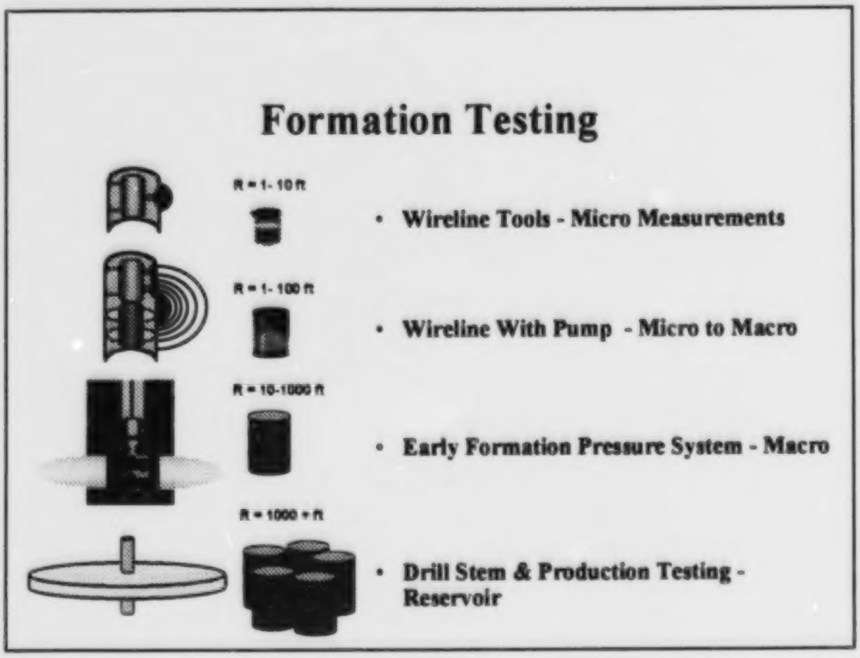
*Paul Ringgenberg
Neal Skinner
Halliburton Energy Services

Multi-Zone Formation Pressure Testing During a Wiper Trip



What is an Early Formation Pressure System?

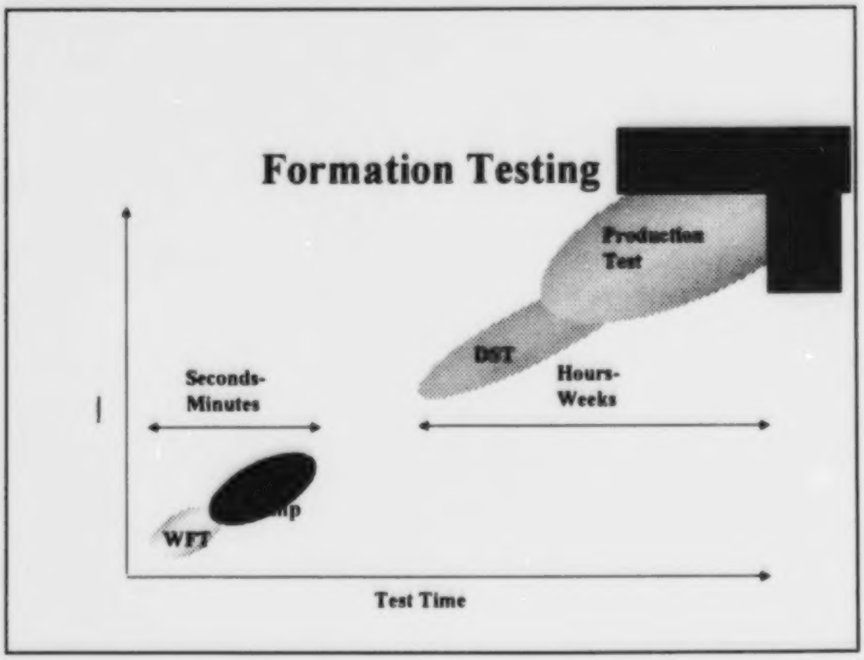
- One of a class of open-hole formation testing tools used to obtain formation pressure and permeability.
- Testing performed as soon as possible after the zone is penetrated such as on a wiper trip.



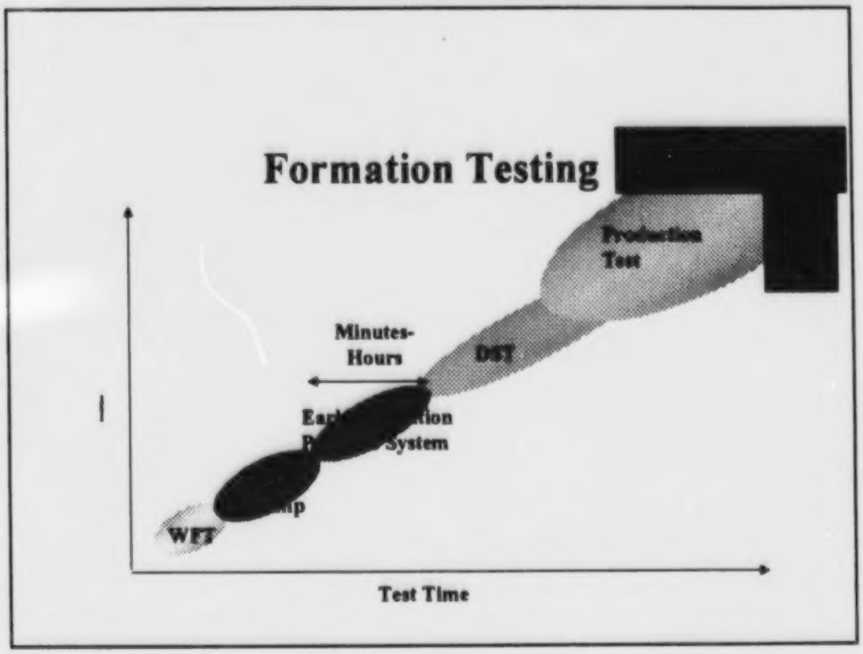
Formation Testing

R = 1- 10 ft
R = 1- 100 ft
R = 10-1000 ft
R = 1000 + ft

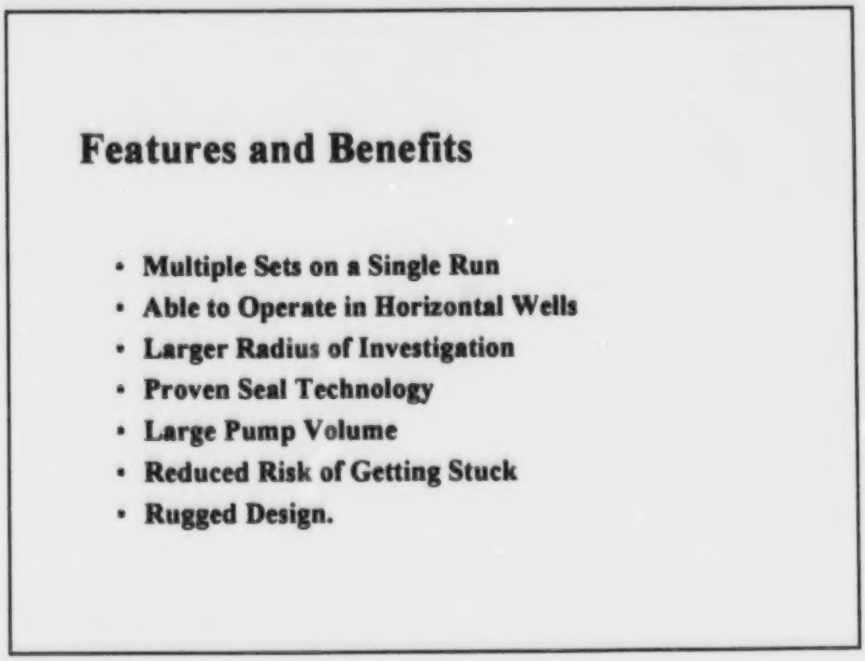
- **Wireline Tools - Micro Measurements**
- **Wireline With Pump - Micro to Macro**
- **Early Formation Pressure System - Macro**
- **Drill Stem & Production Testing - Reservoir**



Formation Testing

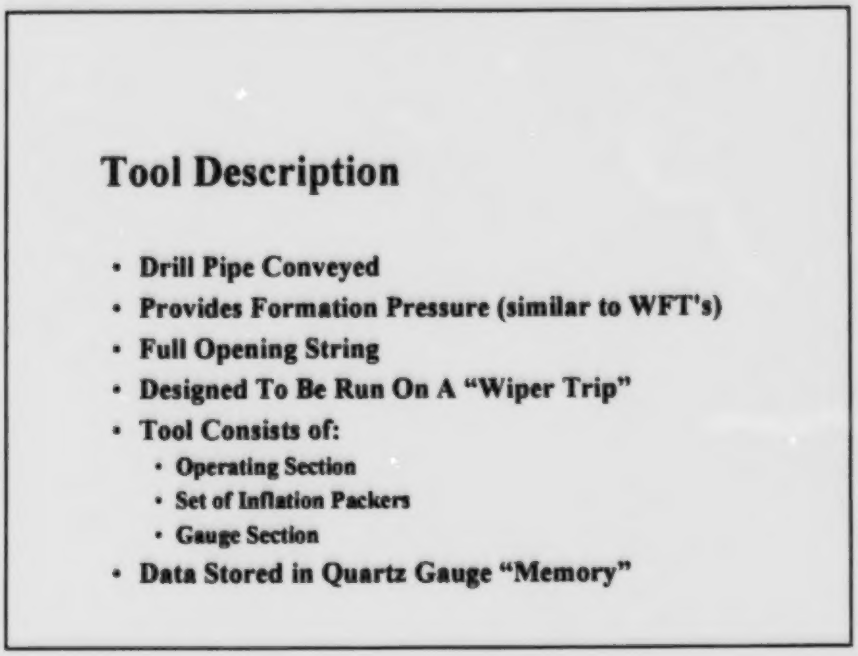


Formation Testing



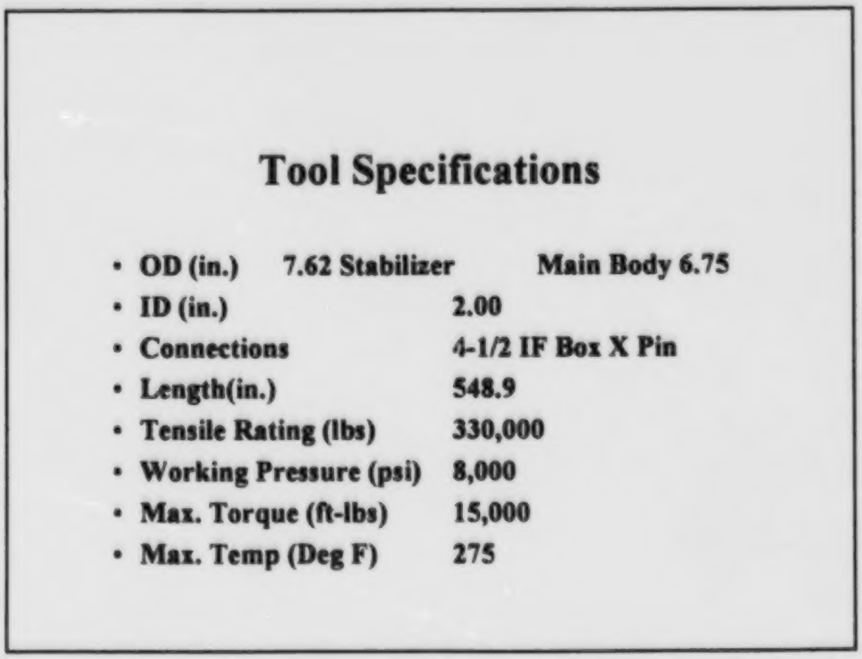
Features and Benefits

- Multiple Sets on a Single Run
- Able to Operate in Horizontal Wells
- Larger Radius of Investigation
- Proven Seal Technology
- Large Pump Volume
- Reduced Risk of Getting Stuck
- Rugged Design.



Tool Description

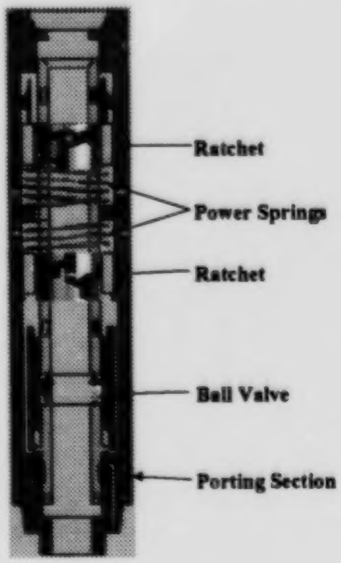
- Drill Pipe Conveyed
- Provides Formation Pressure (similar to WFT's)
- Full Opening String
- Designed To Be Run On A "Wiper Trip"
- Tool Consists of:
  - Operating Section
  - Set of Inflation Packers
  - Gauge Section
- Data Stored in Quartz Gauge "Memory"



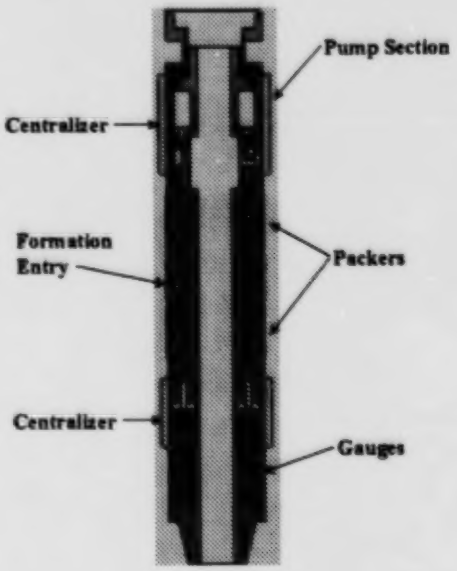
Tool Specifications

• OD (in.)	7.62 Stabilizer	Main Body 6.75
• ID (in.)	2.00	
• Connections	4-1/2 IF Box X Pin	
• Length(in.)	548.9	
• Tensile Rating (lbs)	330,000	
• Working Pressure (psi)	8,000	
• Max. Torque (ft-lbs)	15,000	
• Max. Temp (Deg F)	275	

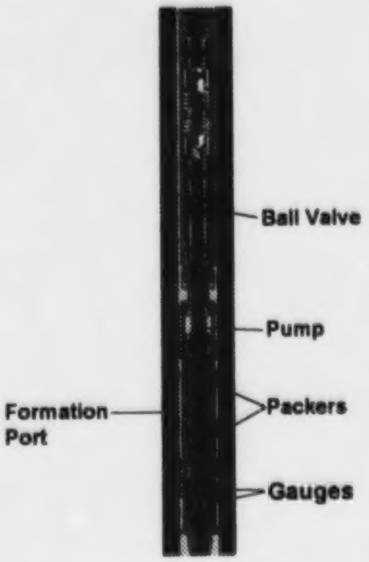
EFPS Top Tool


Ratchet
Power Springs
Ratchet
Ball Valve
Porting Section

EFPS Bottom Tool


Pump Section
Centralizer
Formation Entry
Packers
Centralizer
Gauges

EFPS System


Ball Valve
Pump
Formation Port
Packers
Gauges

Run in Hole and Circulate

Early Formation Pressure System Simulator

L

A Case History of Completing and Fracture Stimulating a Horizontal Well

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Pennzoil
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James Harry
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Society of Petroleum Engineers

SPE 29443

A Case History of Completing and Fracture Stimulating a Horizontal Well

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SPE Members

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Abstract

This paper presents a detailed description of the completion and fracture stimulation of a high-angle well in the Madison formation of the Williston Basin in North Dakota. The case history of the Candee 26-13 HA well is used. The completion and fracture stimulation techniques used on this well resulted in a three and a half-fold increase in the ultimate recovery of the well, in comparison to a vertical well in the same field.

The well was directionally drilled to intersect natural fractures and provide optimal conditions for hydraulic fracture stimulation. To ensure zone selectivity and isolation, the well was cased and cemented. Notching techniques were used to allow hydraulic fracture treatments to be selectively initiated along the wellbore. Matrix acidizing was an essential phase to achieve this goal.

This paper also presents a discussion of how reservoir simulators can be used to optimize the number of fractures needed to cover a given drainage area. In addition, prefracture and postfracture evaluations are discussed.

Introduction

The primary benefit of drilling a horizontal well is to take advantage of a greater effective drainage area than that available from a vertical well drilled in the same area. Fracturing a horizontal well has presented problems because of premature screenouts and high treatment pressures. In most geological formations, the orientation angle of a horizontal well from the maximum horizontal stress plays a crucial role in achieving a successful stimulation treatment. The following three mechanisms related to wellbore orientation relative to the maximum horizontal stress (orientation angle) need to be addressed.[1]

- *Fracture-wellbore communication area.* Two extreme cases, longitudinal and orthogonal fractures, provide maximum (longitudinal) and minimum (orthogonal) communication area between the wellbore and propagating fractures.
- *Fracture geometry near the wellbore.* Fracture geometry is an important factor that may cause early screenouts. Several different fracture geometries can result when a horizontal well is fractured, including multiple fractures, T-shaped fractures, and complex fractures.

References at the end of the paper.

- *Fracture tortuosity near the wellbore.* This phenomenon occurs when the wellbore is oriented in such a way that the fracture must go through a reorientation process. This process results in fracture surface roughness, which restricts flow and can cause premature screenout.

Soliman et al.[2] discussed the situation in which multiple fractures are created from a horizontal wellbore. They used an analytical model to show the effect of fracture conductivity near the wellbore on production performance. The optimum number of fractures along the horizontal wellbore for a given drainage area was also discussed.

Austin et al.[1] emphasized the importance of casing and cementing the horizontal section to allow for fracture-initiation points to place multiple fractures along the horizontal well. Overbey et al.[4], presented a case history on using external casing packers to divide the horizontal section into several zones for fracture stimulation. The objective of their work was to propagate natural fractures and induce additional fractures at each interval.

Owens et al.[3] presented an application of the tip screenout technique in fracturing horizontal wells. The information presented in this paper is based on more than 100 propped fracture treatments placed from horizontal wells.

The main issues discussed in Reference 5 are (1) the importance of casing and cementing for isolation and (2) performing a good cement job at the interval of fracture initiation to help prevent multiple fractures. Stoltz[6] presented case studies of two horizontal wells used for enhanced oil-recovery purposes.

Background

The objective of the Candee 26-34HA project was to determine if a single, high-angle well drilled through the Ratcliffe and Mission Canyon formations of the Williston Basin could recover reserves equal to the reserves recovered from two to three vertical wells completed through the same interval. The test well was spudded on Dec. 27, 1990, and drilled to a total depth of 9,330 ft on Feb. 6, 1991. Total measured depth was 12,115 ft with a lateral offset of 3,300 ft. A 5 1/2-in. casing was cemented to TD. The well is located on a northwest-southeast trending anticlinal feature in a position where significant fracture enhancement occurs because of structural flexure. The wellbore was drilled parallel to the least principal stresses in an east-west direction across the northern nose of the structure. The principal stress directions were determined from structural analysis and regional fracture directions (**Fig. 1**). The pay zone consisted of approximately 125 ft of primarily fractured carbonate with 4 to 6 ft of 10% porous limestone in the Ratcliffe formation. **Fig. 2** shows a schematic of the wellbore.

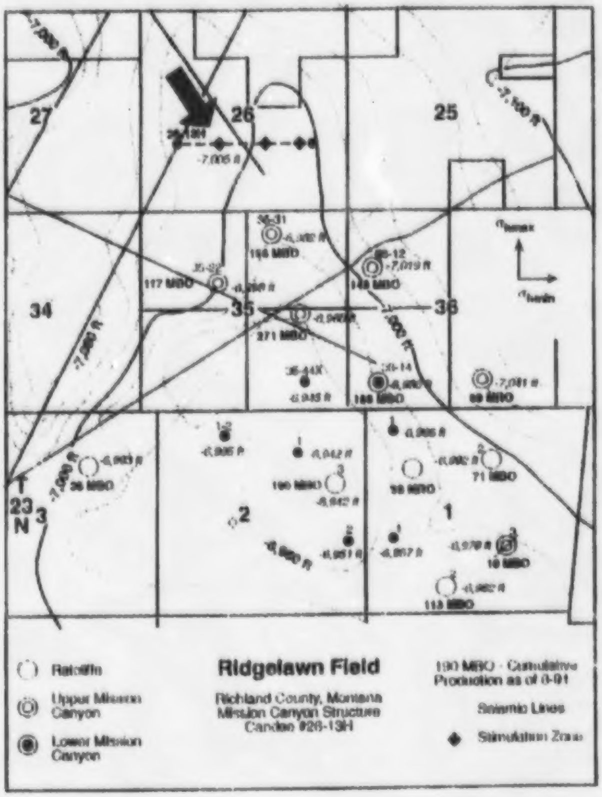

Fig. 1—The principal stress directions determined from structural analysis and regional fracture directions.

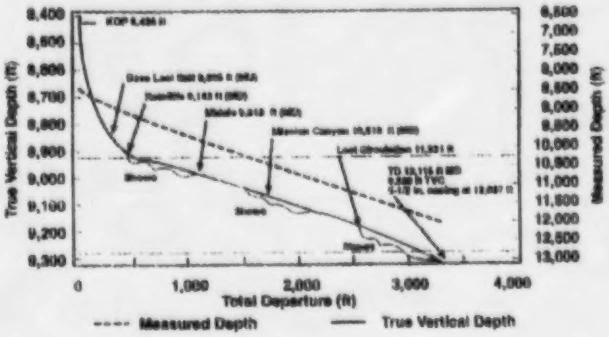

Fig. 2—Wellbore schematic.

Reservoir Considerations

Generally, hydraulic fracturing of a horizontal well is indicated under certain conditions. These conditions include restricted vertical flow, such as those caused by low vertical permeability or impenetrable shale streaks within the productive interval, attempting to intercept swarms of natural fractures with random orientation, and zones with low productivity and/or low permeability.

Once the need for fracturing is established, the orientation of the fractures with respect to the horizontal wellbore must be addressed. Ideally, this decision should be made before the horizontal section is drilled, since the induced fracture direction depends on the orientation of the principal stresses. Fracture orientation can be classified as either longitudinal (where the fracture axis coincides with the wellbore axis) or transverse (where the fracture axis is perpendicular or generally at some angle to the wellbore). Fracture orientation is usually based on reservoir and fracture performance considerations.

The main criterion for transverse vs. longitudinal fractures is the dimensionless fracture conductivity, C_{fd}, as defined by the following equation:

$$C_{fd} = \frac{k_f b}{k L_f} \quad \text{.......} \quad (1)$$

Physically, the C_{fd} compares the flow capacity within the fracture to the flow capacity of the formation along the fracture length. High C_{fd}s indicate excess flow capacity within the fracture, meaning that the fracture's capability to deliver reservoir fluid to the wellbore is high relative to the formation's capability to deliver reservoir fluid to the fracture. This behavior suggests little flow restriction within the fracture. Low C_{fd}s indicate the opposite: the formation's capability to deliver reservoir fluid to the fracture is high relative to the fracture's ability to deliver that fluid to the wellbore. This behavior implies flow restriction within the fracture. When transverse vs. longitudinal fractures are considered, it has been reported that longitudinal fractures are advantageous when the C_{fd} is less than 5 to 10. Transverse fractures are advantageous when the C_{fd} is greater than 5 to 10.[2,8]

An additional reason for selecting transverse fractures is that a horizontal well containing multiple transverse fractures has the potential of contacting more reservoir area than a horizontal well containing longitudinal fractures. The additional "reach" associated with transverse fractures allows accelerated recovery of the reservoir, especially in the area between the fractures at early times. Low-permeability reservoirs will benefit from this completion option.

Certain characteristics of transverse fractures should be carefully considered to help ensure effective fracture completion of a horizontal well.[3,8] Because of the geometry of a transverse fracture's relationship with a horizontal wellbore, the fracture's contact with the wellbore is limited as shown in **Fig. 3, Page 4**. Soliman et al.[2] presented an early-time-transient analytical model for a finite conductivity transverse fracture that describes a linear-radial flow regime. Fluid flows from the reservoir linearly into the fracture. Once the fluid is inside the fracture, it flows radially toward the wellbore. The radial flow causes an additional pressure drop within the fracture at the wellbore called *convergence skin*. Economides et al.[8] presented the following equation for convergence skin factor:

$$(S_{ck})_c = \frac{kh}{k_f b}\left[\ln \frac{h}{2r_w} - \frac{\pi}{2} \right] \quad \text{.......} \quad (2)$$

To overcome the convergence skin effect, high C_{fd} is necessary. Soliman et al.[2] showed that a high C_{fd} tail-in significantly reduces the radial convergence skin effect. In gas wells, non-Darcy flow contributes to the convergence skin. After a fracturing treatment, high C_{fd} is necessary for effective cleanup. The presence of high water saturation in the fracture reduces the fracture conductivity near the wellbore, resulting in an effect similar to convergence skin. Generally, transverse fractures need to be designed for higher C_{fd} values than their vertical well counterparts to overcome the limited contact with the horizontal wellbore.

For the subject well, anticipated C_{fd}s were well above the 5 to 10 range; therefore, transverse fracture geometry was selected. Evaluation of the convergence skin based on Eq. 2 resulted in a skin factor of 0.013, indicating effectively no radial convergence skin effect within the fracture. This result is not surprising because of the high anticipated C_{fd} value resulting mainly from the low formation permeability. Preliminary design indicated a fracture half-length of approximately 400 ft and fracture conductivity of about 1,500 md-ft, resulting in a C_{fd} of more than 100. Even though the C_{fd} is very favorable, it was decided to tail-in with high-conductivity, high-strength proppant to maintain high C_{fd} in the near-wellbore region over time.

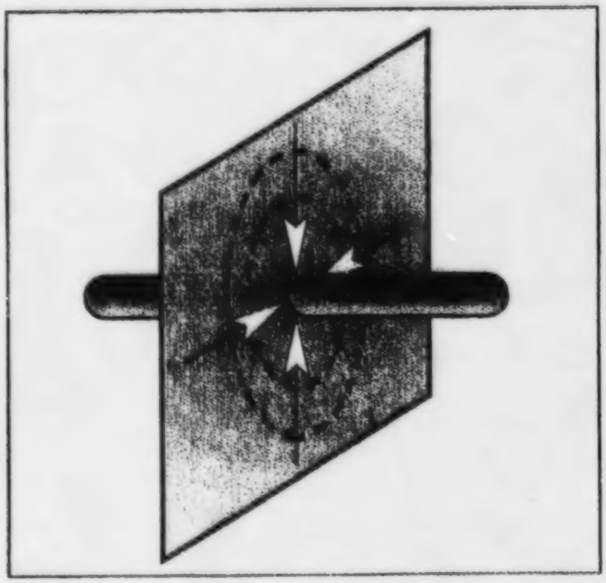

Fig. 3—Fluids radially converge in a transverse fracture approaching a horizontal borehole. This phenomenon causes an unusually high pressure drop in the fluid flow of horizontal wells with transverse fractures.

Rock Mechanics Considerations

When the horizontal section of a wellbore is drilled through the formation parallel to the direction of minimum horizontal stress, σ_{Hmin}, a transverse fracture should be expected during hydraulic fracturing (**Fig. 4**). Transverse fractures initiate and extend at approximately right angles to the wellbore axis. Several different intervals along the horizontal wellbore can be stimulated for optimum reservoir depletion.

A multiple fracture system might be created that could present complex fluid flow problems that hinder a successful stimulation treatment. **Fig. 5** shows the effect of perforated interval length on the number of multiple fractures created. These multiple fractures can

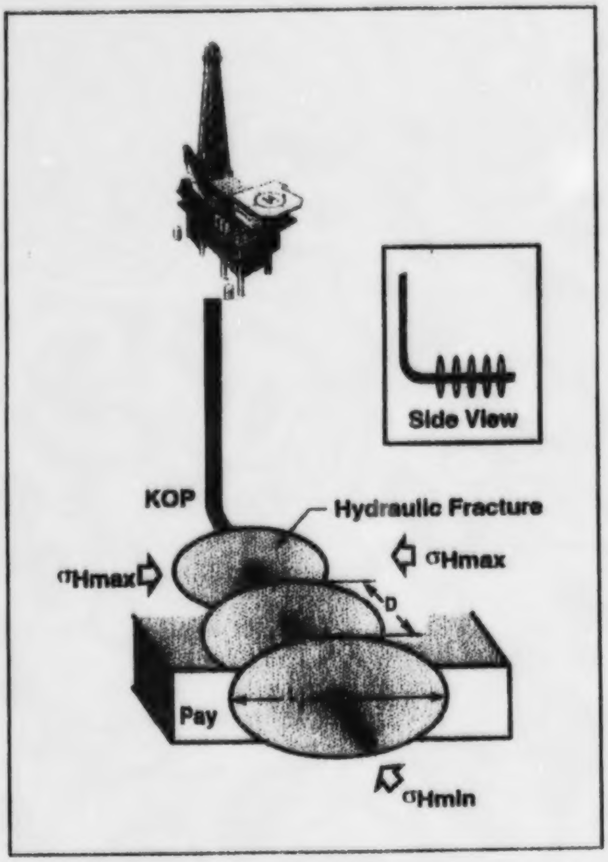

Fig. 4—A horizontal section of a wellbore drilled through the formation parallel to the direction of minimum horizontal stress, σ_{Hmin}.

Fig. 5—Length of the perforation interval affects whether or not multiple fractures are created.

result in reduced fracture width near the wellbore, leading to high treating pressures and/or screenouts.

In practice, it is important to have a clear communication channel between the wellbore and the major fracture propagating under the effect of the unaltered state of stress. Therefore, fracture strands must not be created. To achieve this objective, the following arguments were considered:

- Since the fracture is anticipated to initiate perpendicular to the wellbore (transverse fracture), it is necessary to perforate only a short interval, such as 1 ft.
- To avoid creating T-shaped and/or multiple fractures, it is crucial to ease the near-wellbore stress concentration by creating a large cavity around the wellbore.

The cavity is assumed to dictate the fracture direction and communicate the small fracture width to the wellbore. Creation of the cavity eases the stress concentration around the wellbore, which eliminates the creation of a longitudinal fracture along the wellbore. For example, a wellbore is drilled in the direction of minimum horizontal stress as shown in Fig. 4. The tangential stress at the wellbore and at two locations, in the direction of vertical stress, v, and in the direction of maximum horizontal stress, M, are given as

$$(\sigma_t)_v = 3\sigma_{Hmax} - \sigma_v \quad\quad (3)$$

$$(\sigma_t)_M = 3\sigma_v - \sigma_{Hmax} \quad\quad (4)$$

It is obvious that $(s_t)_v$ is less than $(s_t)_M$, which suggests that a tensile failure at the high and low sides of the wellbore will initiate during hydraulic fracturing, creating a longitudinal fracture along the treated interval. This fracture will propagate in the direction perpendicular to the maximum horizontal stress and must go through a reorientation process to become perpendicular to the minimum horizontal stress. Fracture reorientation can result in a rough fracture surface that a proppant may bridge, possibly causing a screenout.

To avoid these problems, an acid job was used to connect all the slots created around the wellbore and form a cavity. Use of this job design achieved two objectives:

- It encouraged the creation of a single fracture from the cavity surface that was oriented perpendicular to the minimum horizontal stress.
- It created a nonrestricted zone between the fracture and the wellbore.

Perforation Design

Perforations play a crucial role in achieving a successful fracturing treatment in horizontal wellbores. The design of the perforating program (phasing, number, size, and perforated interval length) may depend on fracture initiation geometry. Fracture initiation determines the communication path between the wellbore and fracture plane at the wellbore. Nonplanar fracture geometries, such as multiple, reoriented, T-shaped, and other complex fractures (**Fig. 6, Page 6**), are not advantageous; they adversely affect the potential to achieve the required stimulation treatment. The serious problems that can result because of these nonplanar fracture geometries are listed below.

- When two fractures propagate from the same interval, they share the same rock material as they are developing width. Therefore, instead of having a wide fracture, two narrow fractures result. Adequate fracture width is needed to place proppant slurry inside the fracture. If it is too narrow, proppant may bridge near the wellbore area, causing pressure increases that result from flow restriction.[3] Eventually, screenout occurs when proppant concentration and/or size is increased.

- Fluid leakoff increases with the number of fracture strands, which results in reduced fluid efficiency and premature screenout.
- Wall waviness of a reoriented fracture causes increased friction pressure, which leads to high treatment pressure and operational problems.

Therefore, for a successful hydraulic fracturing treatment, a perforation design should be in phase with the anticipated fracture direction to ensure (1) a fracture that propagates perpendicular to the minimum horizontal stress, which gives an optimum width, (2) a single fracture to propagate, which creates a longer fracture, and (3) reduction of breakdown and extension pressures, which is preferred in any fracturing treatment.

In this case, the fracture is anticipated to initiate perpendicular to the wellbore (transverse fracture). To avoid initiating multiple fractures, it is recommended to extensively perforate (360° phasing) a short interval (a few feet) of the wellbore. If the formation is a carbonate, it is recommended to start with a stage of HCl at the matrix flow injection rate to create a better communication channel between the wellbore and the main fracture.

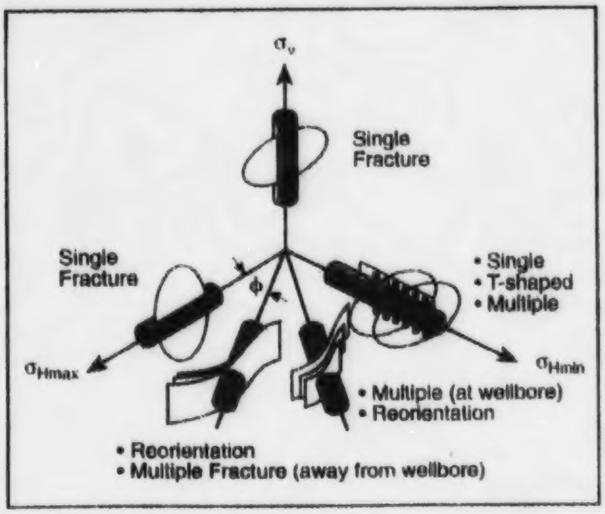

Fig. 6—Nonplanar fracture geometries.

Optimizing the Number of Fractures

When transverse fractures exist, a major design criterion is the optimum number of fractures to create. A very good indication of the most effective number of fractures can be determined by simulating production for various numbers of fractures. Economics can then be applied to these few cases and the most effective fracture number can be determined. An analytical model has recently been presented in the literature,[9] but it does not consider reservoir boundaries. This model may be useful for investigating early-time production, but long-term production, including the effect of boundaries, must be considered before the most effective number of fractures can be determined. Until an analytical model is developed that considers multiple fractures in a horizontal wellbore in a closed reservoir, numerical simulation must be used to determine the optimum number of fractures necessary to effectively produce a horizontal wellbore. A technique to determine the optimum number of fractures with a fractured well numerical simulator is described in Reference 2.

Optimizing the number of fractures for the subject well was accomplished using the technique presented in Reference 2. The total drainage area for the well/fracture system was 459 acres (4,000 ft x 5,000 ft). Horizontal well length was 3,000 ft, and the fractures considered had 400 ft half-length and were identical. Results of the simulation runs are presented in **Fig. 7** as a plot of cumulative liquid production vs. the number of fractures for various times after fracturing. Initially, the relationship between cumulative production and number of fractures is linear because the formation has low permeability and each fracture is producing from its own drainage area with no interference from adjacent areas. After a few months of production, the fractures establish their own drainage area and interference between adjacent fractures begins. After a very long time (much longer than shown on Fig. 7), the reservoir between the outermost fractures has effectively been drained, and the behavior of the system approaches that of a horizontal well containing a single fracture. Based on this behavior, the optimum number of fractures is time-dependent. A time horizon needs to be chosen to arrive at a realistic value for the number of fractures that balances recovery with cost. For the subject well, a time of about 24 months was chosen as the time horizon. At 24 months (Fig. 7), the slope of the curve is constant up to three fractures, then it decreases and rapidly flattens after four to five fractures. Based on the diminishing slope of the cumulative production vs. time curve at 24 months, four or five fractures would be the most effective number of fractures for the subject well. However, after considering the behavior of the well/fracture system, designers considered economics and selected three fractures for the subject well.

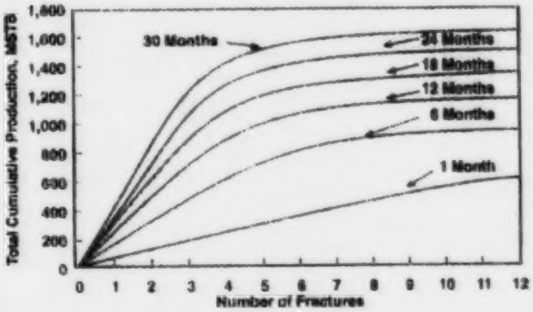

Fig. 7—Cumulative liquid production vs. the number of fractures for various times after fracturing.

Stimulation Treatment

The stimulation treatment was designed to achieve the following objectives:

- *To create a cavity near the wellbore.* To ease the near-wellbore restriction, an acid stage was used to communicate all the hydrojetted notches. **Fig. 8** presents a schematic of the longitudinal slots created via hydrojetting. **Fig. 9** shows a conceptual representation of what might have happened after an acid treatment. **Fig. 10** shows the creation of the main fracture as it initiates from the cavity.
- *To prevent the natural fractures intersecting the wellbore from initiating and propagating multiple fractures.* For fluid-loss contol, 100-mesh sand was pumped after the pad.
- *To help withstand the high compressive stress near the wellbore and reduce the pressure drop resulting from the radial flow convergence.* High-strength, coarse proppant was used as a tail-in stage.

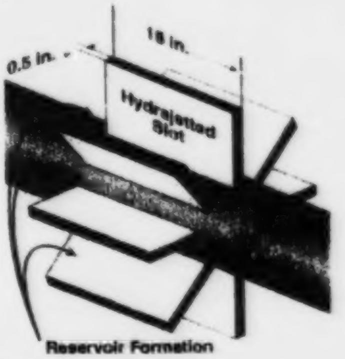

Fig. 8—Longitudinal slots created by hydrojetting.

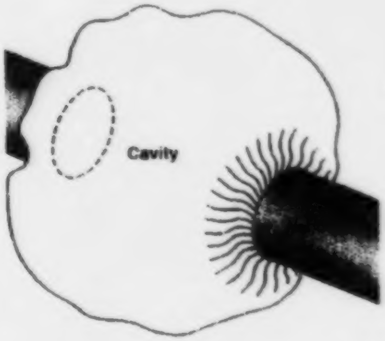

Fig. 9—Conceptual representation of what might have happened after an acid treatment.

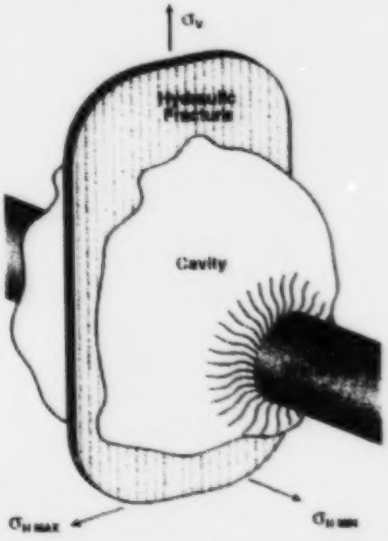

Fig. 10—Creation of the main fracture as it initiates from the cavity.

Based on the above guidelines, the following treatment design was implemented:

Treatment Materials

a. 2,500 gal of 15% HCl

b. 15,000 lb of 100-mesh sand at 1 lb/gal for 20,000 gal

c. 73,700 lb of 20/40 mesh sand

d. 27,500 lb of 16/20 mesh synthetic proppant

Job Procedure

a. 2,500 gal of 15% HCl

b. 12,000 gal of prepad

c. 25,000 gal high-temperature fracturing gel

20,000 gal high-temperature fracturing gel with 1 lb/gal 100-mesh sand

400 gal spacer

d. 12,000 gal high-temperature fracturing gel 0.25 lb/gal 20/40 mesh sand

5,000 gal high-temperature fracturing gel 0.50 lb/gal 20/40 mesh sand

5,000 gal high-temperature fracturing gel 0.75 lb/gal 20/40 mesh sand

5000 gal high-temperature fracturing gel 1.00 lb/gal 20/40

e. 25,000 gal high-temperature fracturing gel ramped from 1 to 5 lb/gal 20/40 mesh sand

f. 7,000 gal high-temperature fracturing gel ramped from 5 to 6 lb/gal 16/20 synthetic proppant

g. 11,000 gal saltwater flush

The injection rate was 50 bbl/min. Initial surface pressure was 3,050 psi during pad. At the 0.5 lb/gal stage, surface pressure was 2,940 psi. For job completion and before shutdown, surface pressure was 3,580 psi. The total volume of fluid injected was 136,162 gal.

Production Increase

The well was completed in four intervals spaced evenly along the wellbore. Each interval was notched along an interval of no more than 2 1/2 ft, with hydrojets. The slots were then acidized with approximately 1,000 gal of 15% HCl to help ensure connectivity with the formation and then fracture-treated with 50,000 to 160,000 lb of 20/40 synthetic proppant. Each interval was isolated and treated separately.

Initial production began in July 1991 at an average daily rate of 290 BOPD and 300 BWPD. As of June 1994, average daily production has declined to 80 BOPD and 147 BWPD, and total cumulative recovery is now 137,000 bbl of oil. Ultimate recovery is estimated at 450,000 bbl of oil.

Fig. 11 shows the projected performance of the Candee and the normalized production curve for the average 11 vertical offsetting wells. A typical vertical well has an initial production rate of 95 BOPD and will recover approximately 120,000 bbl of oil over a 10- or 12-year economic life. The Candee, in contrast, is expected to recover over 450,000 bbl of oil during its economic life—approximately 3.5 times a typical vertical well.

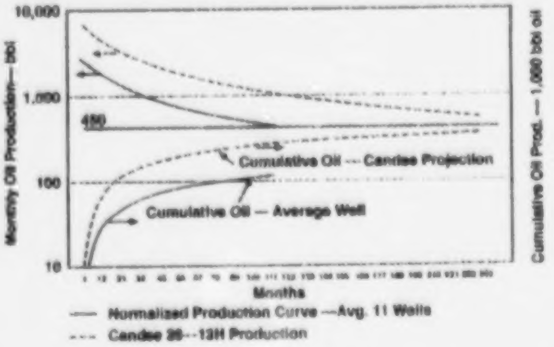

Fig. 11—Projected performance of the Candee and the normalized production curve for the average 11 vertical offsetting wells.

Conclusions

- A horizontal wellbore was successfully drilled, completed, and fracture-stimulated in the Williston Basin, North Dakota.
- Casing and cementing a horizontal well is essential to provide zone selectivity and isolation during fracture stimulation.
- Single-point initiation was necessary to successfully propagate transverse fractures. A successful technique to hydrojet slots along the casing to initiate a single transverse hydraulic fracture was presented.
- The number of transverse fractures along the horizontal well was optimized based on production increase and economics.
- The stimulation treatment was designed to prevent multiple fractures, withstand the high near-wellbore compressive stress, and overcome the near-wellbore convergence skin.
- A 3.5-fold production increase was obtained when compared to offset vertical wells.

Nomenclature

b = fracture width, ft

C_{fD} = dimensionless fracture conductivity

h = formation thickness, ft

k = formation permeability, md

k_f = fracture permeability, md

L_f = fracture half-length, ft

r_w = wellbore radius, ft

$(S_{ch})_c$ = radial convergence skin factor

σ_v = vertical stress

σ_{Hmax} = maximum horizontal stress

σ_{Hmin} = minimum horizontal stress

Acknowledgments

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"The Dirt on Mud Loss:" Interpreting Mud Loss Data From Mississippian Horizontal Wells in S.E. Saskatchewan

*Ken J. Wawro
Mike Ware
Talisman Energy

"The Dirt on Mud Loss"

Interpreting Mud Loss Data From Mississippian Horizontal Wells in S.E. Sask.

(1998-05)

TALISMAN

Abstract

Successful horizontal drilling in SE Saskatchewan's Mississippian oil pools is dependent on accurate reservoir characterization. Unfortunately, gathering conclusive information directly from horizontal wells is often difficult and expensive. Talisman Energy Inc. is using mud loss data to help analyze the quality of reservoir encountered while drilling horizontally.

By drilling horizontal wells slightly overbalanced with a water-based mud system, we have observed fluctuating rates of mud loss. Through our team's understanding of the mechanical and reservoir factors that can cause these fluctuations we interpret them as reservoir related responses occurring at the drill bit. By combining this with other wellsite data we have developed a set of qualitative rules that aid in understanding these heterogeneous reservoirs and resulting horizontal well production.

The practice of monitoring mud loss was introduced to supplement other data acquired at the wellsite such as rate of penetration, total gas readings, cutting descriptions and oil shows. Together they are used to geo-steer the well into the best portions of the reservoir and identify zones prone to water production, which can then be isolated during well completion.

This presentation summarizes the factors that can impact mud loss, how the data is interpreted and the benefits realized.

Low Tech Mud Loss Monitoring

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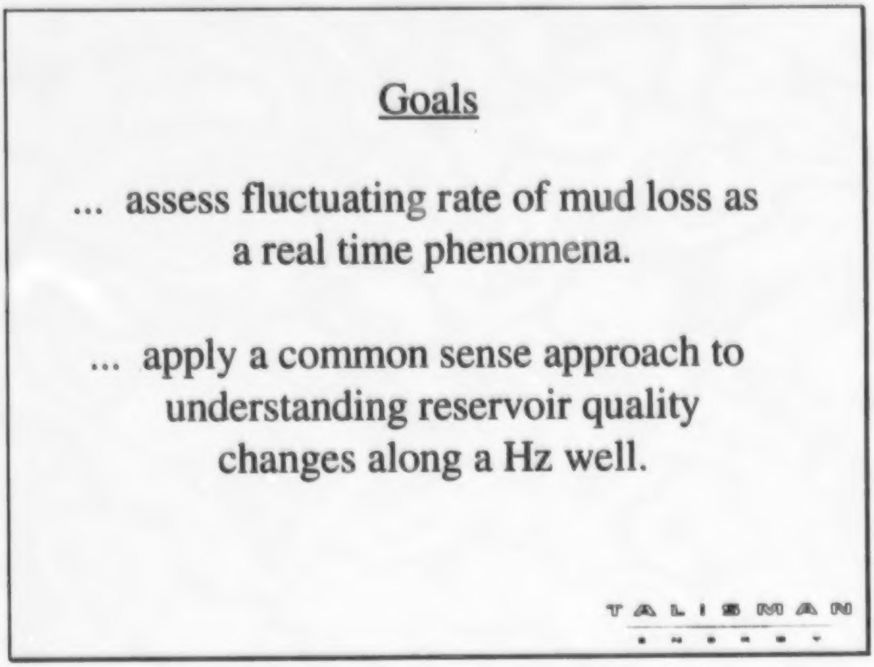
The monitoring process is designed to simply obtain a mud volume balance over a specified drilling duration. Training field personnel preceded the success of data collection. This photograph is of a positive displacement meter that measures volumes added to the mud system. The mud tanks are gauged to determine volume changes over a certain time period. In our case hourly readings are acquired. Corresponding measured depths are recorded from the geolograph. Periodic mud tank clean out volumes are recorded. Volumes required to displace drilled material are deducted. The resulting volume change with time relates to the rate of mud loss into a specific section of the reservoir.



Goals

... assess fluctuating rate of mud loss as a real time phenomena.

... apply a common sense approach to understanding reservoir quality changes along a Hz well.

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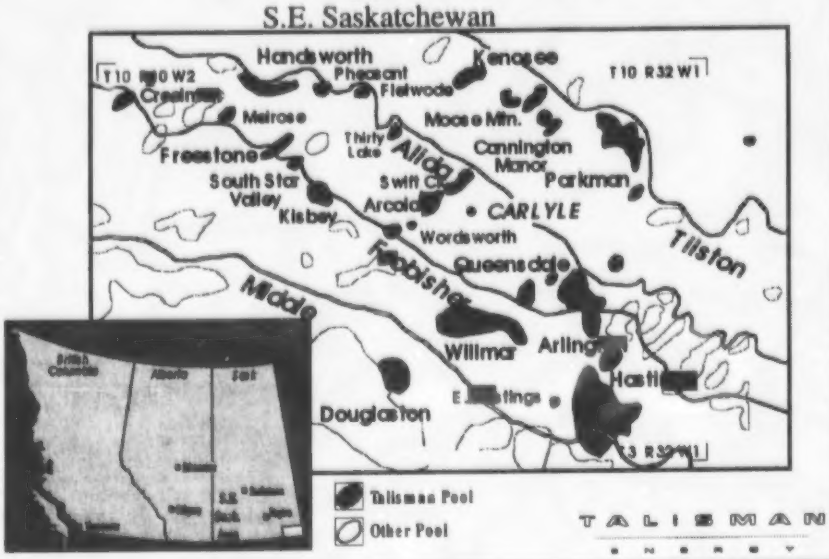
These goals give a prelude to what will be presented with a footnote that results are interpretive but basic understanding of the principles at work and experience have made this tool an integral part of Talisman's reservoir characterization efforts and horizontal well completion strategy.

Mississippian Oil Pools

S.E. Saskatchewan


Handsworth
Pheasant
Fletwode
Kenosee
T10 R30 W2
Creelman
Melrose
T10 R32 W1
Moose Mtn.
Thirty Lake
Alida
Cannington Manor
Freestone
South Star Valley
Kisbey
Swift C.
Arcola
CARLYLE
Parkman
Wordsworth
Tilston
Frobisher
Queensdale
Midale
Willmar
Arlington
Hastings
E. Hastings
Douglaston
T3 R32 W1
British Columbia
Alberta
Sask
S.E. Sask.
Talisman Pool
Other Pool
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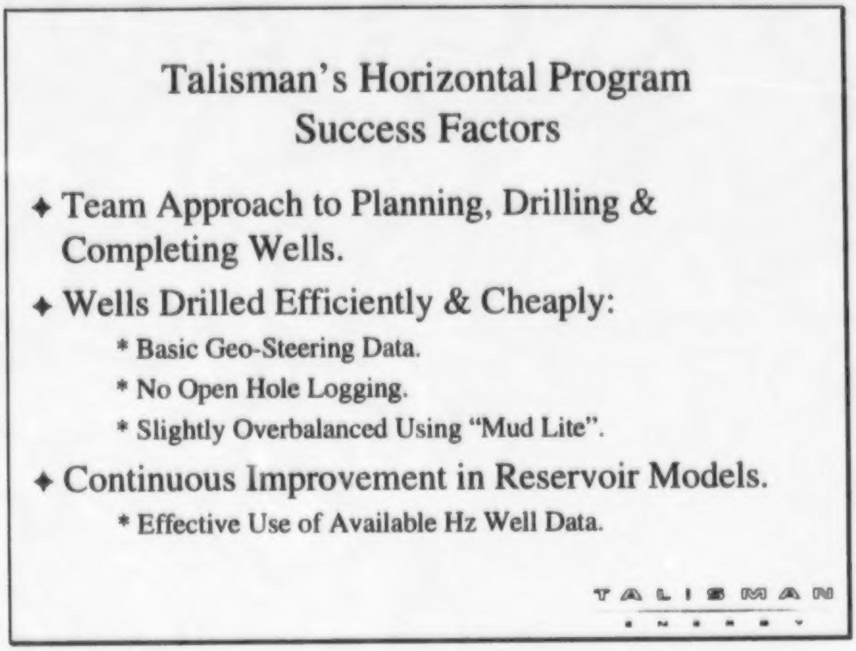
Talisman's SE Saskatchewan operations cover some 20 Mississippian oil pools where we have drilled a total of 120 single and multilateral horizontal wells since 1992. The area represented is located approximately 200 km (125 mi.) SE of Regina.



Talisman's Horizontal Program Success Factors

- Team Approach to Planning, Drilling & Completing Wells.
- Wells Drilled Efficiently & Cheaply:
  - * Basic Geo-Steering Data.
  - * No Open Hole Logging.
  - * Slightly Overbalanced Using "Mud Lite".
- Continuous Improvement in Reservoir Models.
  - * Effective Use of Available Hz Well Data.

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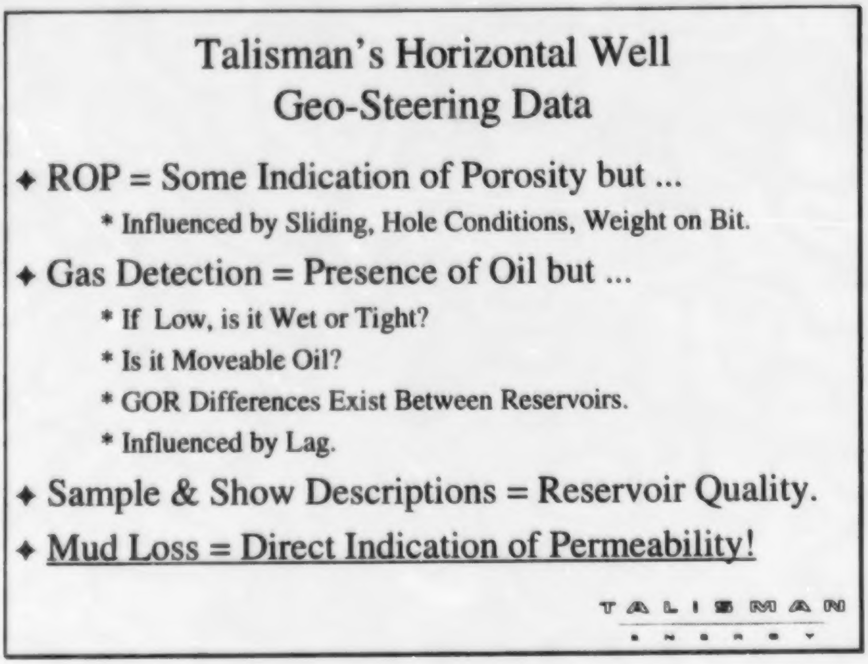
"Mud Lite" refers to Talisman's low-density mud system. Use of mud loss data demonstrates our team's innovative efforts to better understand our reservoirs. The data costs nothing to acquire and minimal time to analyze and has proven beneficial.



Talisman's Horizontal Well Geo-Steering Data

- ROP = Some Indication of Porosity but ...
  - * Influenced by Sliding, Hole Conditions, Weight on Bit.
- Gas Detection = Presence of Oil but ...
  - * If Low, is it Wet or Tight?
  - * Is it Moveable Oil?
  - * GOR Differences Exist Between Reservoirs.
  - * Influenced by Lag.
- Sample & Show Descriptions = Reservoir Quality.
- Mud Loss = Direct Indication of Permeability!

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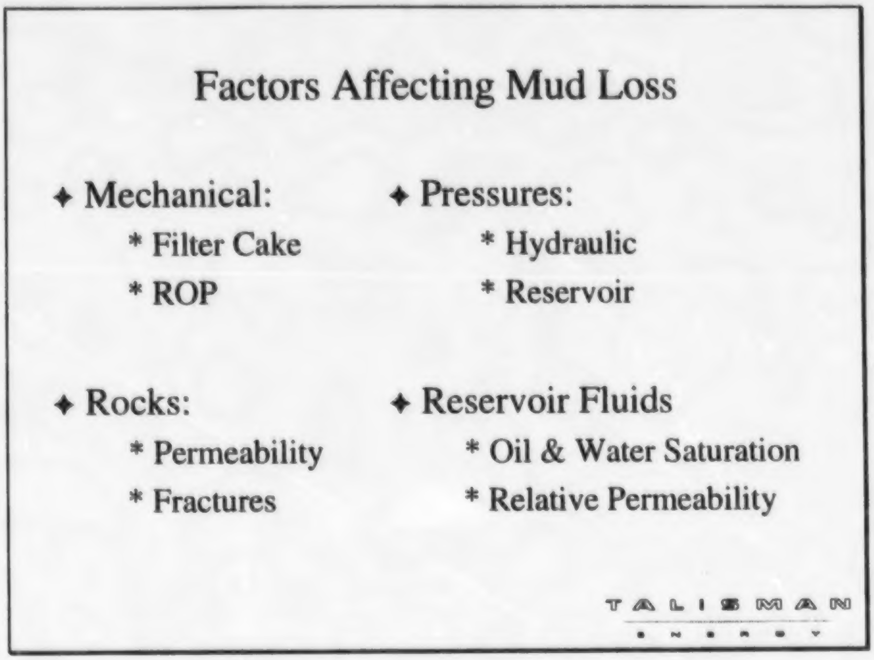
Basic geo-steering data has shortcomings. Mud loss data gives us the unique opportunity to assess in-situ permeability, which improves reservoir characterization as will be discussed.



Factors Affecting Mud Loss

- Mechanical:
  - * Filter Cake
  - * ROP
- Pressures:
  - * Hydraulic
  - * Reservoir
- Rocks:
  - * Permeability
  - * Fractures
- Reservoir Fluids
  - * Oil & Water Saturation
  - * Relative Permeability

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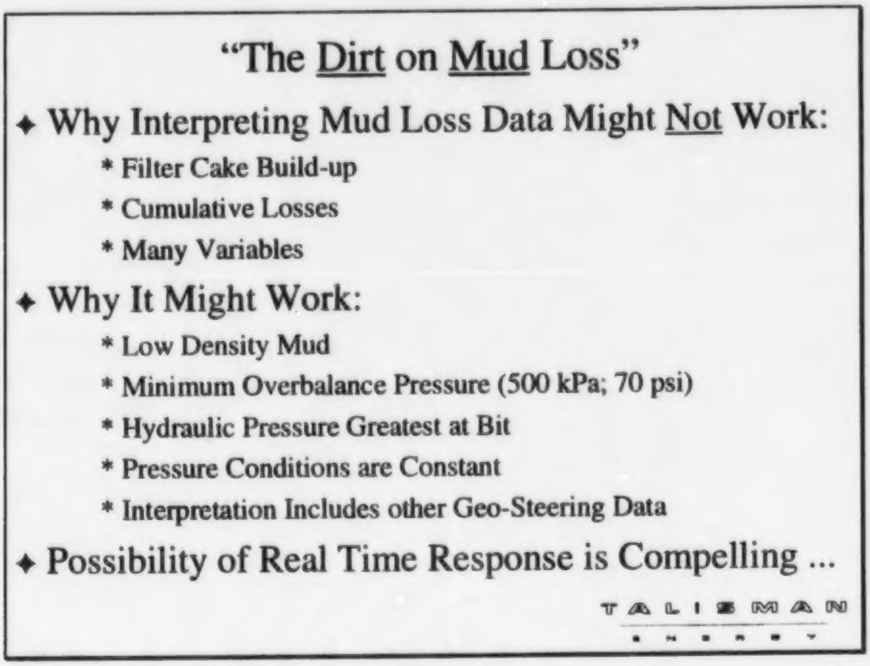
Identifying the mechanical and reservoir related factors and how each may affect mud loss aided in understanding what the data was telling us. We have concluded that the most influential factors affecting mud loss are reservoir related and include permeability, reservoir fluid saturation and relative permeability.



"The Dirt on Mud Loss"

- Why Interpreting Mud Loss Data Might Not Work:
    - * Filter Cake Build-up
    - * Cumulative Losses
    - * Many Variables
- Why It Might Work:
    - * Low Density Mud
    - * Minimum Overbalance Pressure (500 kPa; 70 psi)
    - * Hydraulic Pressure Greatest at Bit
    - * Pressure Conditions are Constant
    - * Interpretation Includes other Geo-Steering Data
- Possibility of Real Time Response is Compelling ...

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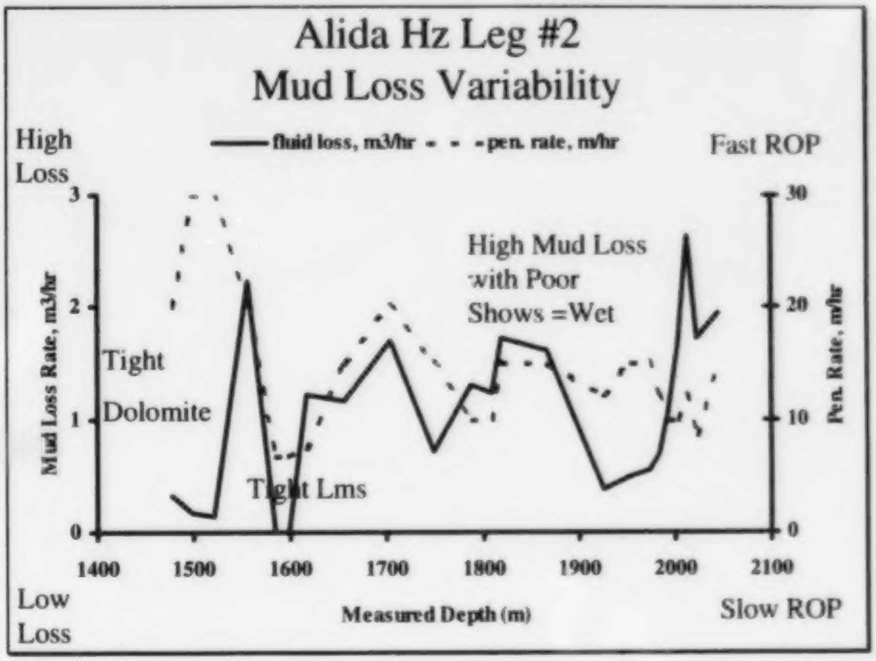
At the outset, we recognized that there were good reasons why the technique might not work. By understanding that some factors were constant and others could be discounted, we were able to conclude that mud loss data has significance. One important realization is that the mud system's hydraulic pressure is greatest at the bit. This is a function of Talisman's use of low-density mud, which results in hydrostatic pressure being only slightly overbalanced at the formation. The static and dynamic forces at the bit then have the greatest combined effect diminishing the impact of filter cake build-up and cumulative losses as is demonstrated by the following example.



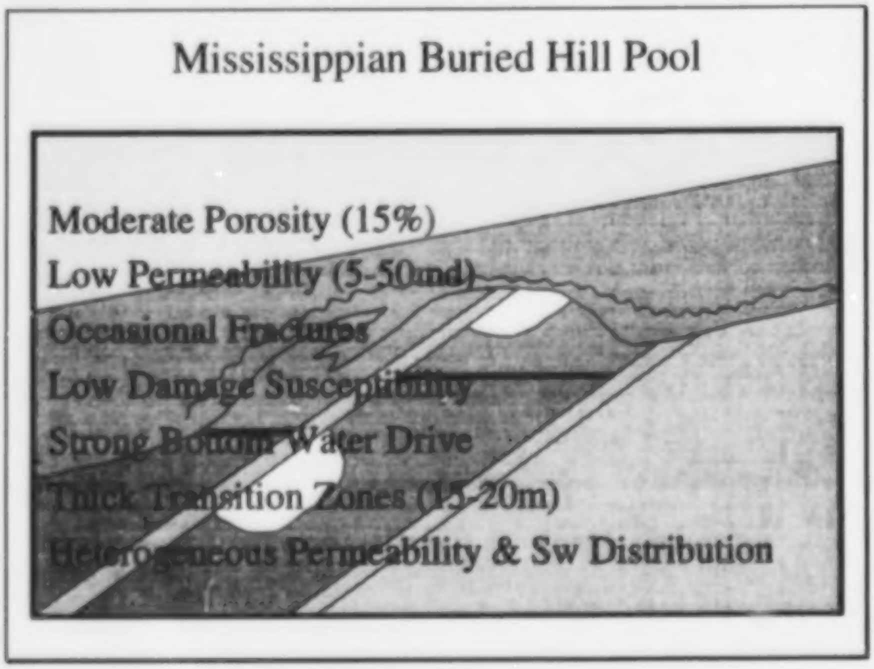
The key illustration of this example is the fluctuation in mud loss, which reinforces the conclusion that filter cake build-up and cumulative loss influences are minor especially considering Leg 1 is open at the time of drilling Leg 2.

Using this example the following points demonstrate the reservoir characterization process we employ.

1.) The dolomite at 1500m MD is described as having high porosity with minor staining. The fast ROP is responding to porosity while low mud loss is responding to low permeability. It is realized that penetration rate can also influence the rate of mud loss, and we assess this by also analyzing normalized data.
2.) The dense limestone described at 1600m MD was confirmed by the slow rate of penetration and zero mud loss.

3.) High mud loss in intervals with low gas readings and oil staining has been confirmed to produce significant volumes of water. We can distinguish between tight and productive wet zones.

To appreciate this claim the affects of reservoir permeability, fluid saturation and relative permeability will be discussed.



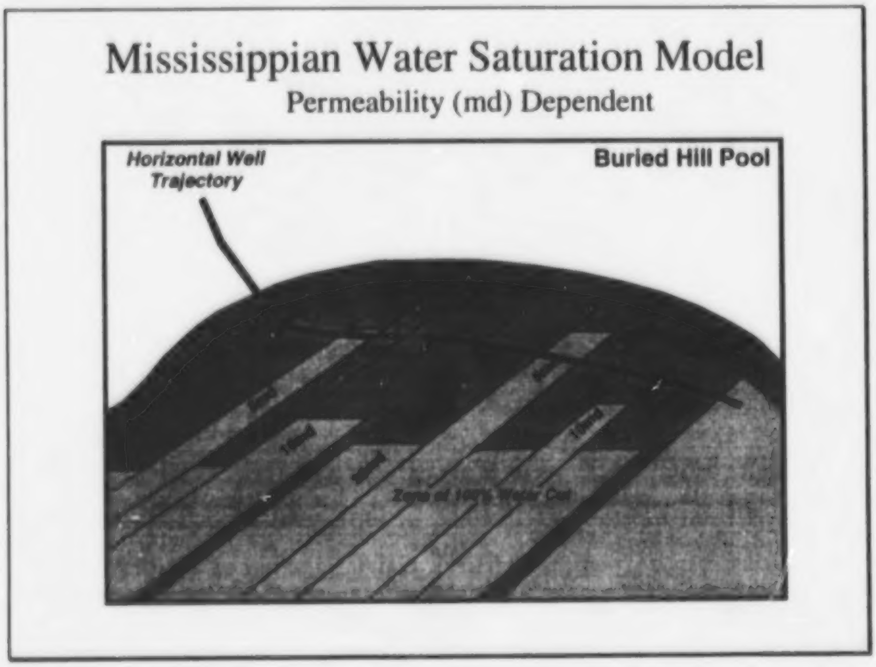
Mississippian Buried Hill Pool

Moderate Porosity (15%)
Low Permeability (5-50md)
Occasional Fractures
Low Damage Susceptibility
Strong Bottom Water Drive
Thick Transition Zones (15-20m)
Heterogeneous Permeability & Sw Distribution

The features of a typical Mississippian Buried Hill Pool include:

1.) Buried hill profile caused by erosion.
2.) Caprock or altered zone of varying thickness.
3.) Complex internal facies relationships.
4.) Bottom seals and internal seals which can create multiple O/W contacts.
5.) Strong bottom water pressure support.

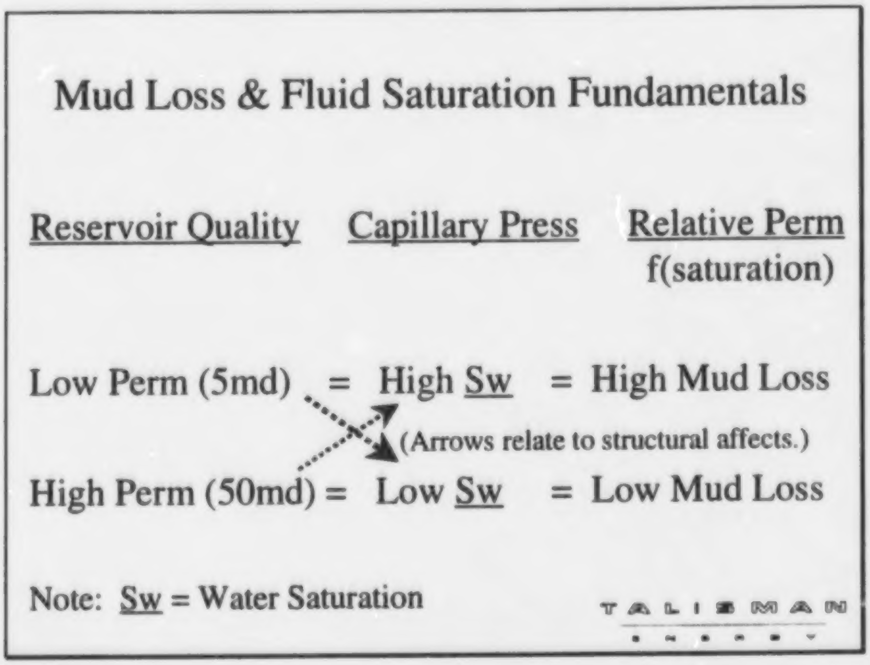
6.) Thick transition zones, which cause most of our reservoirs to initially contain moveable water.
7.) Heterogeneity in permeability, which due to capillary pressure affects, results in varying water saturation at the same structure within the reservoir as illustrated below.


Mississippian Water Saturation Model

Permeability (md) Dependent

Capillary pressure effects can be dramatic at the generally low permeability levels encountered. Wet zones can occur adjacent to zones that produce significant oil volumes.

The next step to understanding the reservoir factors that influence mud loss is to apply the fundamentals of relative permeability. Its' impact is demonstrated below.



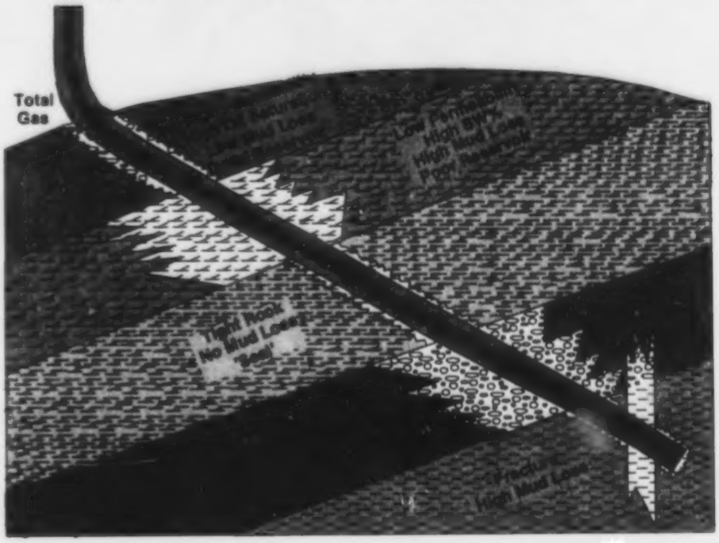
Mud Loss & Fluid Saturation Fundamentals

Reservoir Quality		Capillary Press		Relative Perm f(saturation)
Low Perm (5md)	=	High Sw	=	High Mud Loss
High Perm (50md)	=	Low Sw	=	Low Mud Loss

(Arrows relate to structural affects.)

Note: Sw = Water Saturation

It is this concept and our water saturation model that helps us understand why the rate of mud loss fluctuates as we drill. With all data considered, and the fundamentals understood, a qualitative analysis is possible. Our interpretations have successfully identified zones that produce unacceptably high volumes of water.



Typical Mud Loss Interpretations

Total Gas
Mud Loss
Low Permeability
High BVW
High Mud Loss
Poor Reservoir
Tight Rock
No Mud Loss
"Seal"
Fracture
High Mud Loss

This diagram further illustrates the reservoir conditions at work. Deeper "invasion" signifies higher rates of mud loss. The following real life responses have been observed:

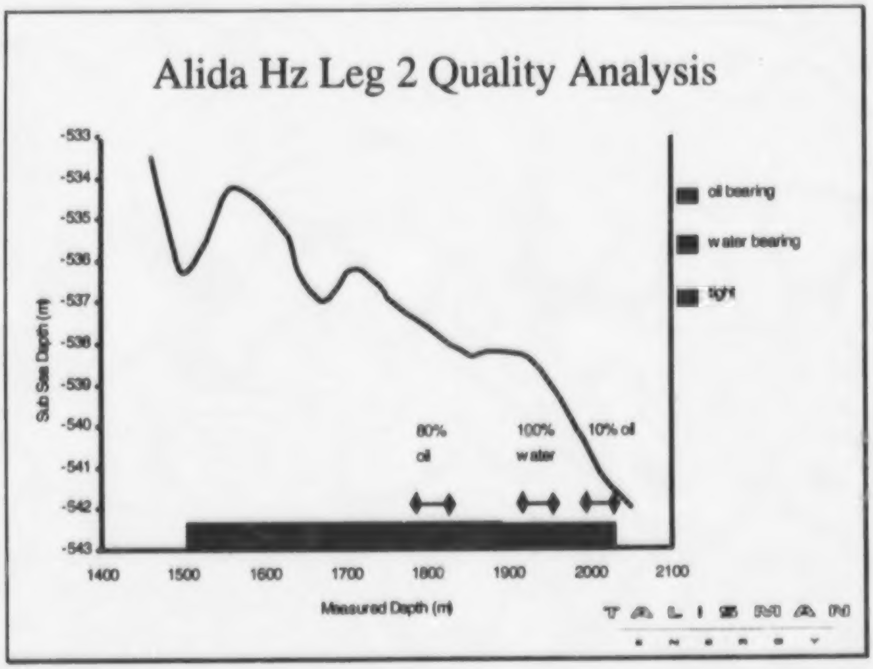
1.) Highly permeable zones, at a high structure, experience low mud losses due to low water saturation and low relative permeability to water.
2.) Conversely, high losses can occur in low permeability zones due to high water saturation and high relative permeability to water. These zones in fact would have lower air permeability than the previously described zone.
3.) High mud losses have been observed in highly porous microcrystalline zones exhibiting high gas readings. Due to low permeability however these zones have produced significant volumes of water.
4.) Highly permeable zones, at low structure will, due to increased water saturation and relative permeability to

water, exhibit mud loss rates greater than a structurally higher zone of similar quality.

5.) Fractures can often be readily identified and isolated. They don't always result in sustained mud loss.

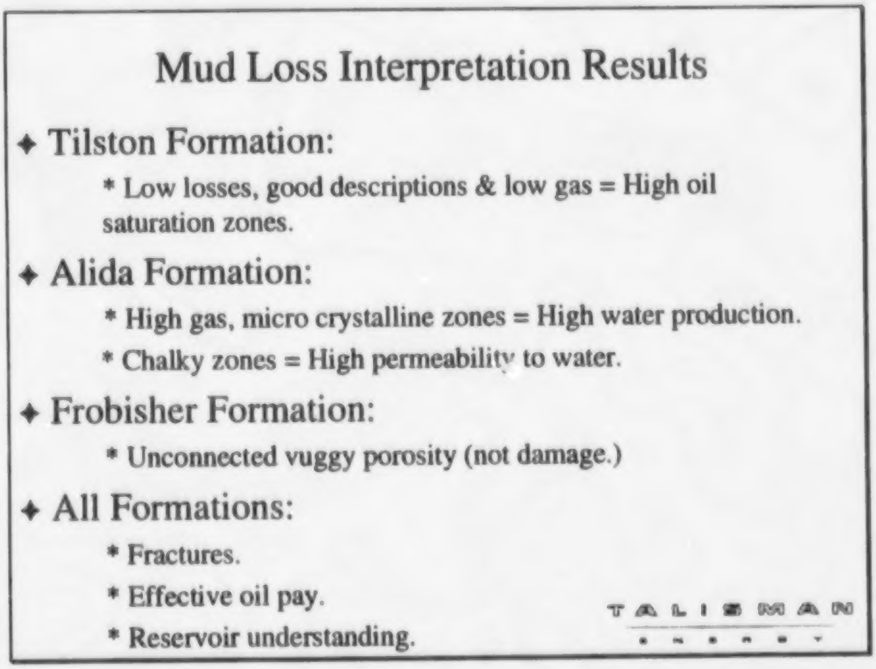
6.) With an understanding of relative permeability the quality of production from different horizontal sections can be predicted; what sections should result in higher oil cut.

The following is an example of how the interpretation is displayed.



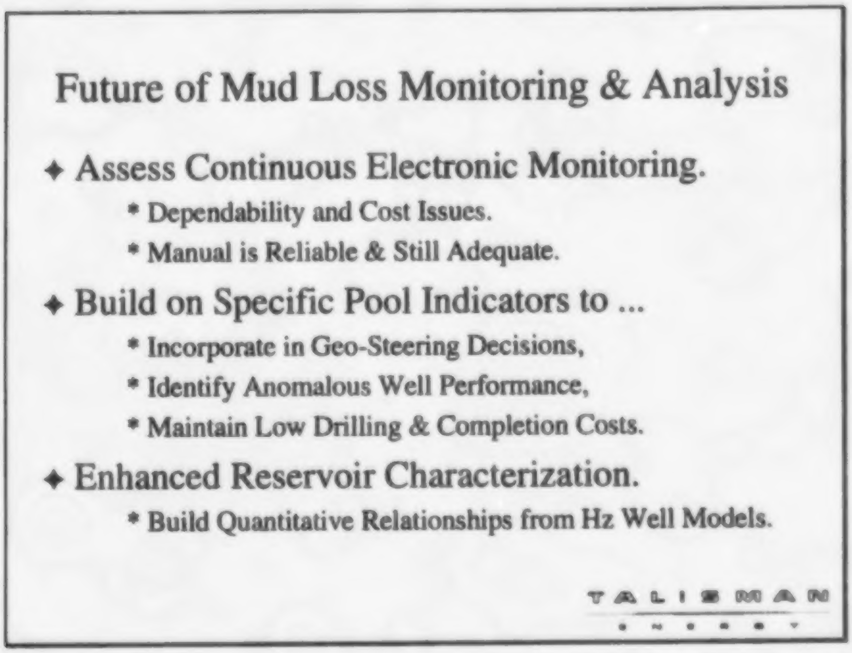
We combine all relevant horizontal well information. The colored bar represents what we envision the reservoir consists of as we drill horizontally; zones of varying permeability, as was depicted in previous diagrams. Early confirmation of interpretations by interval swabbing has in fact permitted a reduction in swabbing requirements. Zones prone to water production can be more easily identified and targeted for deciding how best to complete a well.

Following are a few formation specific characterizations that have resulted from mud loss analysis.



Mud Loss Interpretation Results

- ✦ Tilston Formation:
  - * Low losses, good descriptions & low gas = High oil saturation zones.
- ✦ Alida Formation:
  - * High gas, micro crystalline zones = High water production.
  - * Chalky zones = High permeability to water.
- ✦ Frobisher Formation:
  - * Unconnected vuggy porosity (not damage.)
- ✦ All Formations:
  - * Fractures.
  - * Effective oil pay.
  - * Reservoir understanding.



Future of Mud Loss Monitoring & Analysis

- Assess Continuous Electronic Monitoring.
  - Dependability and Cost Issues.
  - Manual is Reliable & Still Adequate.
- Build on Specific Pool Indicators to ...
  - Incorporate in Geo-Steering Decisions,
  - Identify Anomalous Well Performance,
  - Maintain Low Drilling & Completion Costs.
- Enhanced Reservoir Characterization.
  - Build Quantitative Relationships from Hz Well Models.

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Our team continues to advance the interpretation of and reservoir understanding that mud loss data provides. Manually acquired data is still adequate at the current degree of interpretation.

In conclusion...

SE Saskatchewan Mud Loss Conclusions

- Data Provides Real Time Relative Permeability Information.
- When Used in Combination with Other Geo-steering Data ... Interpretations Contribute to Reservoir Understanding.
- Can Applied to Completion Strategy:
    - * Easily Locate High Water Producing Zones.
    - * Reduces Time & Cost.
- Interpretations Improve with Each Well.
    - * Always Learn Something.

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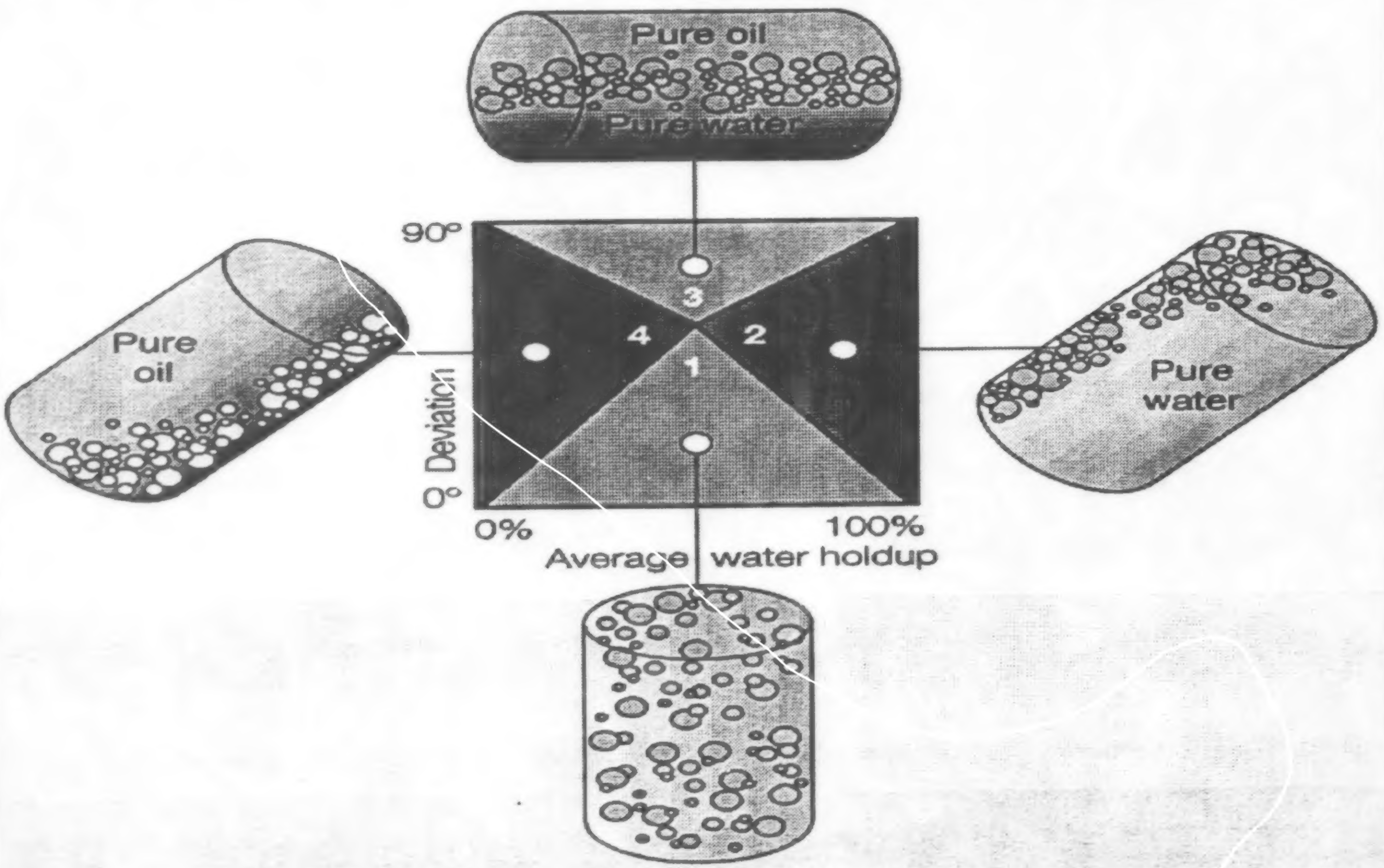
Co-author: Mike Ware
Acknowledgment: Allison A. Walker

N

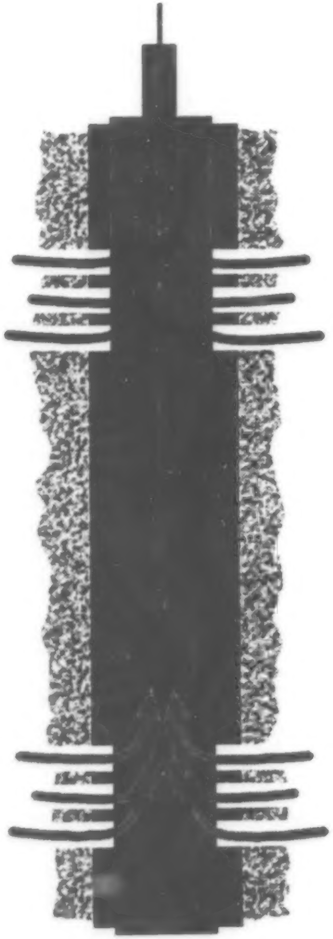
Production Logging in Horizontal Wells

*Joe Poole
Troy Riggins
Schlumberger Oilfield Services

Oil and Water Flow Regimes

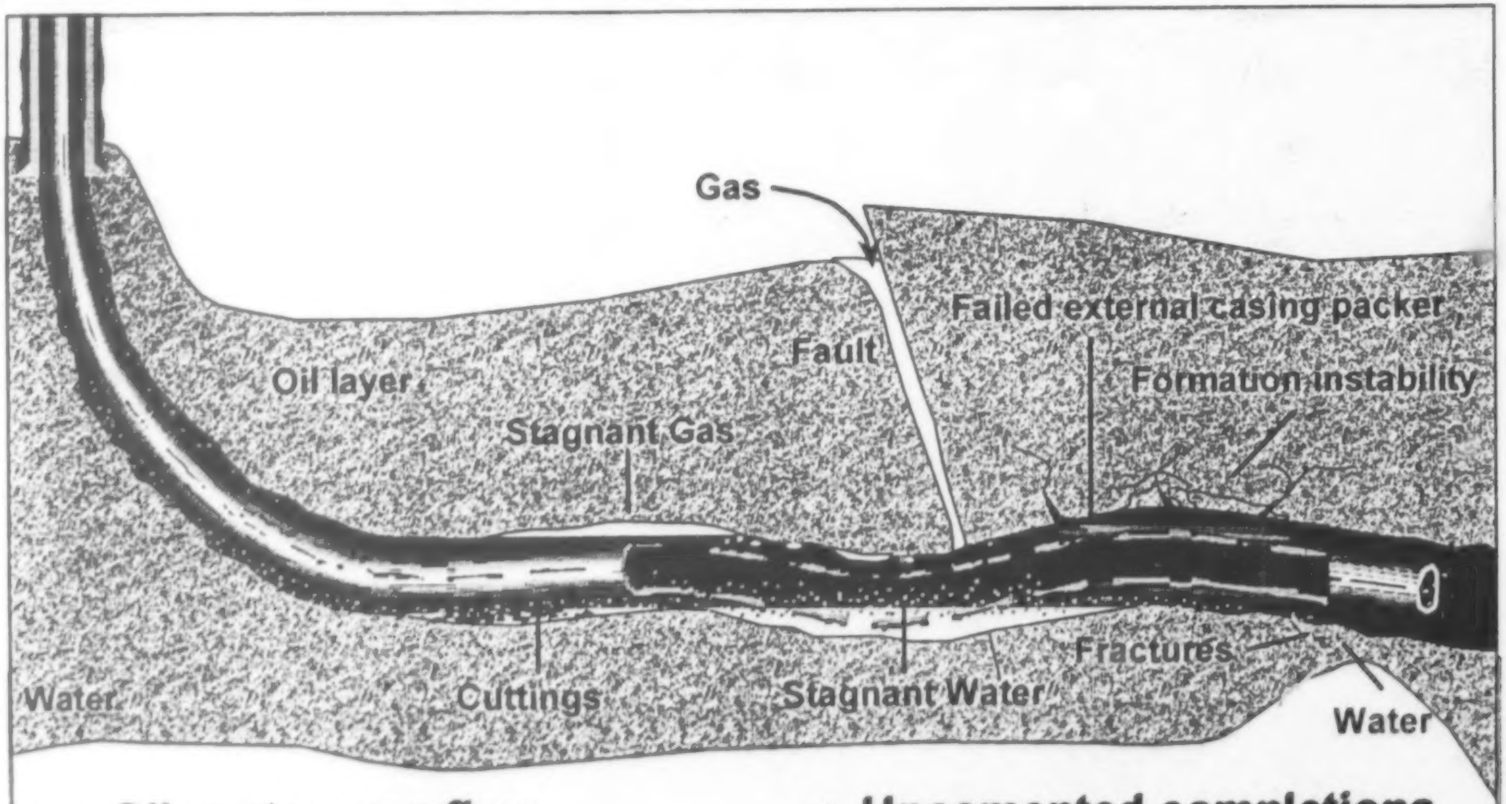

Pure oil
Pure water
90°
3
4
2
1
Pure oil
Pure water
Deviation
0°
0%
100%
Average water holdup

Conventional Production Logging Sensors



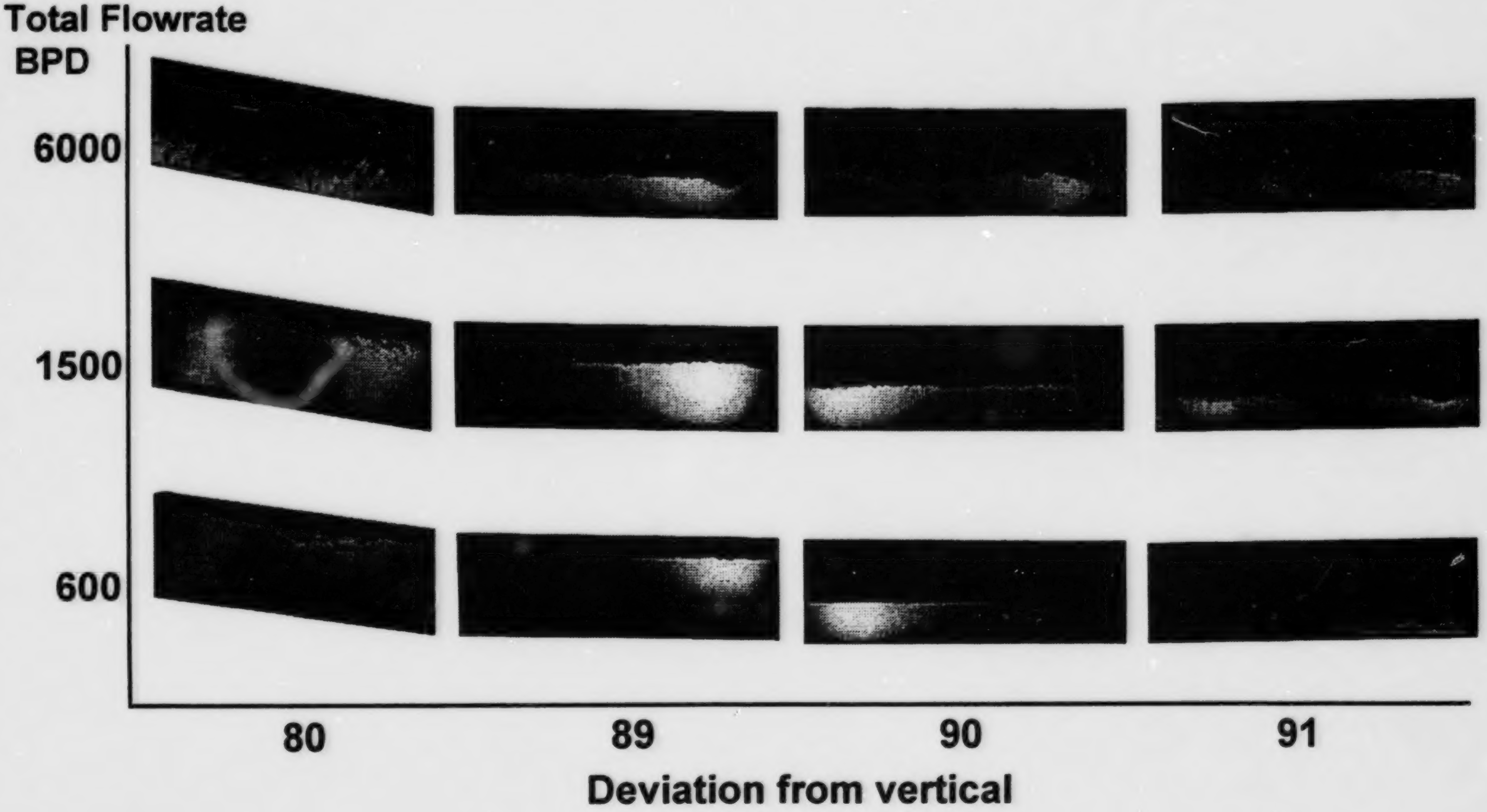
- ◆ Gradiomanometer
- ◆ Spinner
- ◆ Temperature
- ◆ Pressure

Deviated & Horizontal Well Challenges

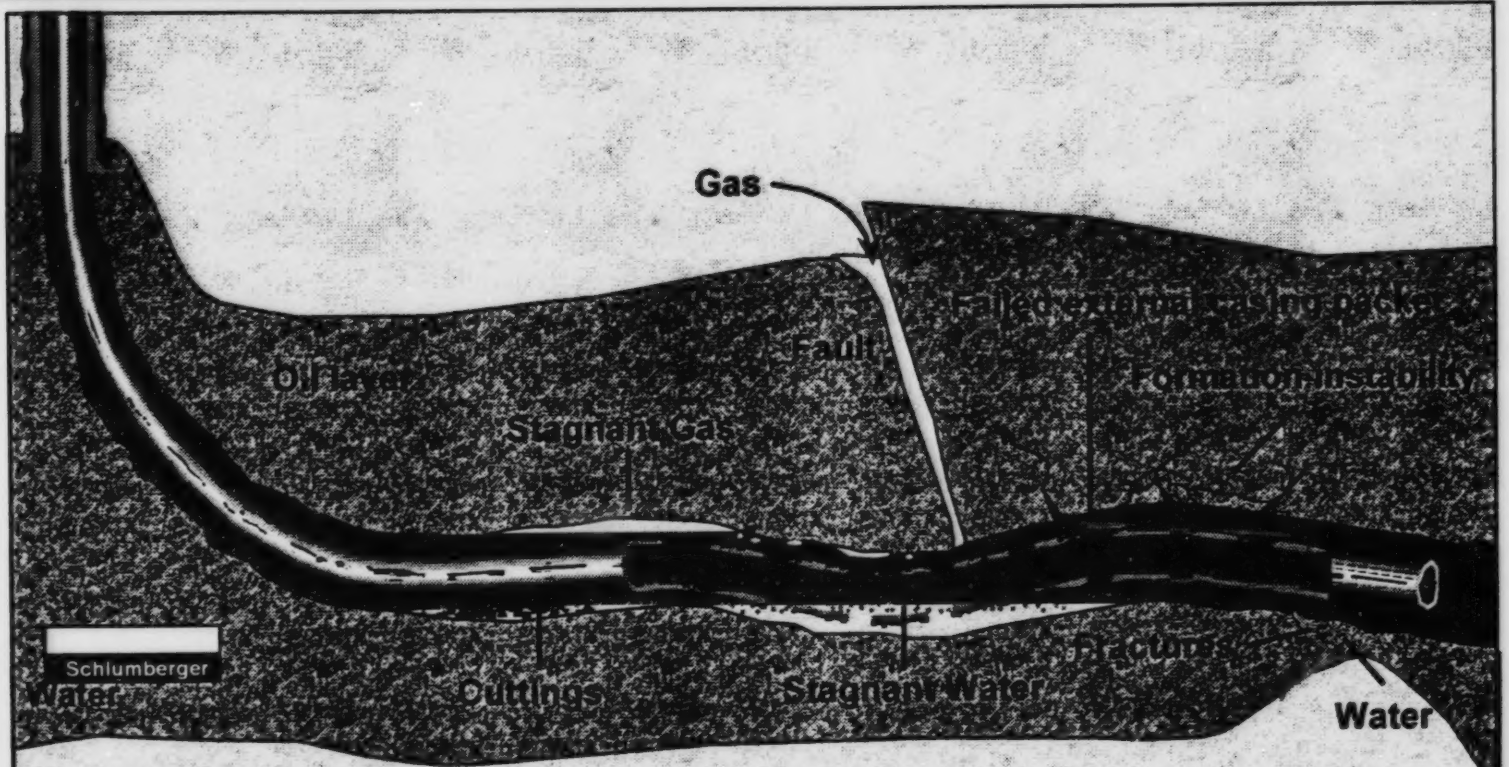

Gas
Fault
Failed external casing packer
Formation instability
Oil layer
Stagnant Gas
Fractures
Water
Cuttings
Stagnant Water
Water

- Oil, water, gas flow
- Stratified & down flow
- Water sumps, gas & oil traps
- Uncemented completions
- Slotted liners, annular flow
- Failed ECP's

Water-Oil Stratified Flows in 5.5 in. Casing - Water Cut is 50%


Total Flowrate
BPD
6000
1500
600
80
89
90
91
Deviation from vertical

Flagship Service Approach


Gas
Failed external casing packer
Fault
Oil layer
Formation instability
Stagnant Gas
Schlumberger
Water
Cuttings
Stagnant Water
Fracture
Water

- Image the flow regime
- Multiple independent measurements
- Velocity * hold-up * area = flow

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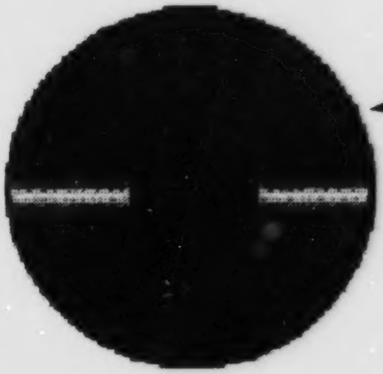
Flow Measurement Principle

- In order to measure flowrate it is necessary to measure the *area and the velocity* occupied by each flowing phase.
- The holdup of each phase is a dimensionless number that expresses the area occupied by a phase as a fraction of the total area such that the holdups sum to unity, i.e. (holdup of water)+(holdup of oil) = 1.
- Therefore flowrate is computed by the product of holdup x area x velocity.

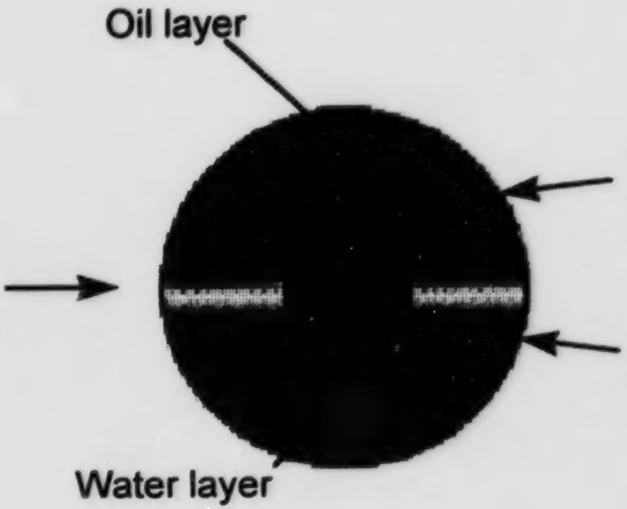


Cross-sectional view of an oil-water stratified flow, showing the tool centred in the well (real data).

Flowrate of oil is computed from oil velocity and area in red

Flowrate of water is computed from water velocity and area in blue.

Horizontal Well Production Logging Toolstring Requirements



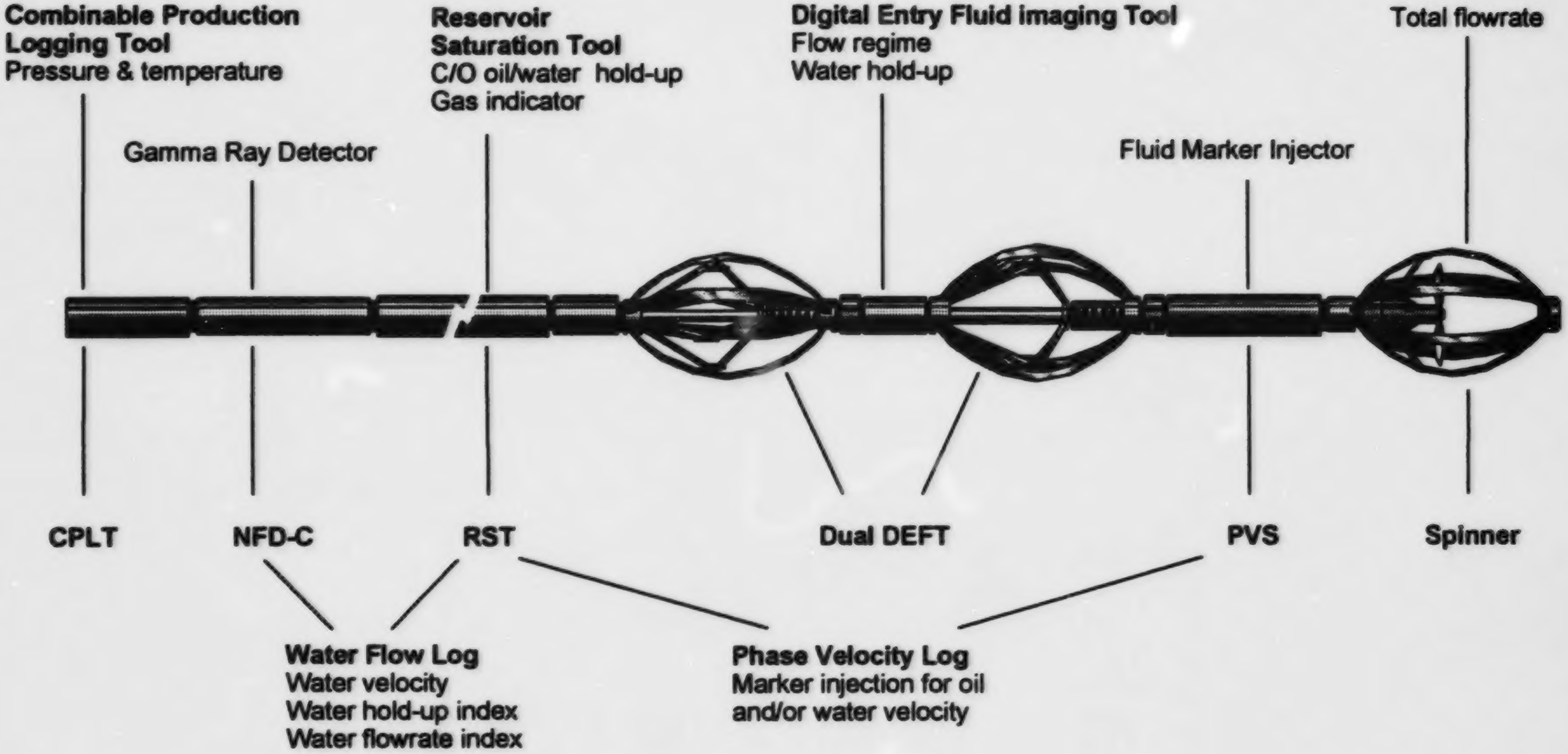
Cross-sectional view of an oil-water stratified flow, showing the tool centred in the well (real data).

Flowrate of oil is computed from oil velocity and area in red

Flowrate of water is computed from water velocity and area in blue.

- In to measure oil and water rates in horizontal wells a toolstring must therefore have the capability of measuring oil and water velocities and holdups as well as pipe area via a caliper, or as known input.
- A toolstring that only responds to velocity or holdup in isolation will not be able to distinguish changes in these quantities induced by well deviation from those due to genuine entries. An ***integrated*** approach is required.

Integrated Production Logging Toolstring



Combinable Production Logging Tool
Pressure & temperature

CPLT

Gamma Ray Detector

NFD-C

Reservoir Saturation Tool
C/O oil/water hold-up
Gas indicator

RST

Digital Entry Fluid imaging Tool
Flow regime
Water hold-up

Dual DEFT

Fluid Marker Injector

PVS

Total flowrate

Spinner

Water Flow Log
Water velocity
Water hold-up index
Water flowrate index

Phase Velocity Log
Marker injection for oil
and/or water velocity

Flagship Service Answer Products

The hold-up and velocity of each phase must be measured by the toolstring for accurate flowrate diagnosis. Very small changes in well deviation can cause large changes in these quantities independently of any fluid entry.

Velocity:

- –Water velocity from:
  - •**WFL Water Flow Log**
  - •**PVL Phase Velocity Log**
- –Oil velocity from:
  - •**PVL Phase Velocity Log**

Hold-Up:

- –Water and Oil hold-up from:
  - •FloView Plus
  - •**WFL Water Flow Log** relative water hold-up index
  - •C/O ratio from **RST Reservoir Saturation Tool** (TPHL)
- –Gas hold-up from:
  - •**RST Reservoir Saturation Tool** Near/Far Inelastic counts (TPHL)

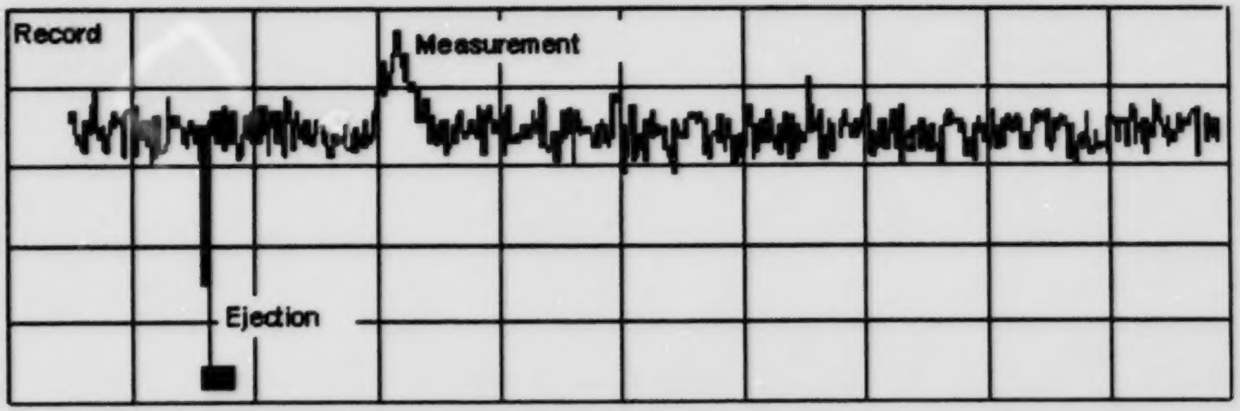
Flowrate:

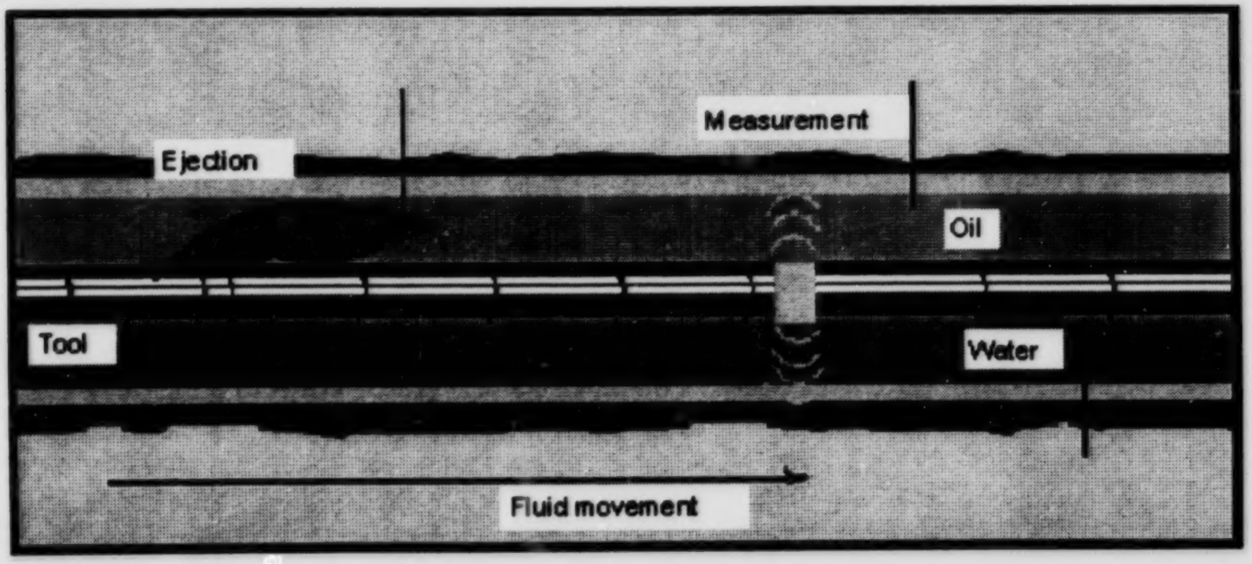
- •Oil and water rates from velocity and hold-up products
- •Total rate from the spinner (in appropriate flow regimes)
- •Gas rate from spinner and gas hold-up
- •**WFL Water Flow Log** relative water flowrate index

Other Products:

- –Oil and Water saturation from **RST Reservoir Saturation Tool** Sigma and C/O
- –Pressure and temperature (including gas entry detection)

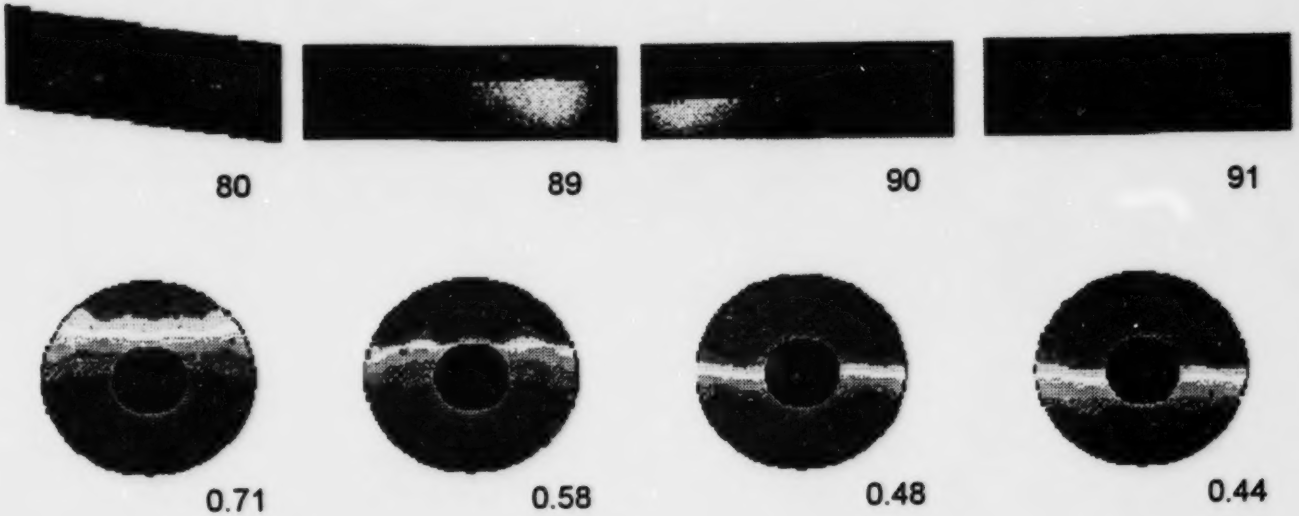
Phase Velocity Log Technique

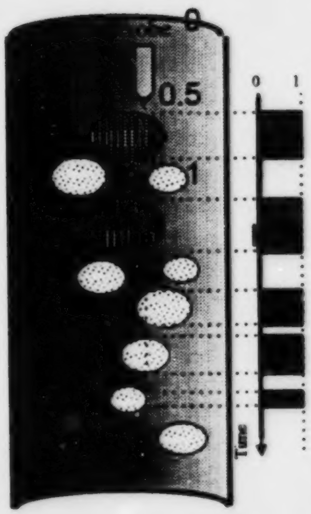


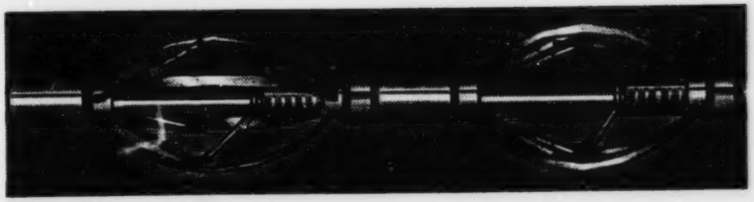

Ejection
Measurement
Oil
Tool
Water
Fluid movement

Dual FloView Images in Oil-Water Flows

Degrees
Deviation
from Vertical
Qo = Qw = 750 BPD




0
0.5
1
0
1
Time



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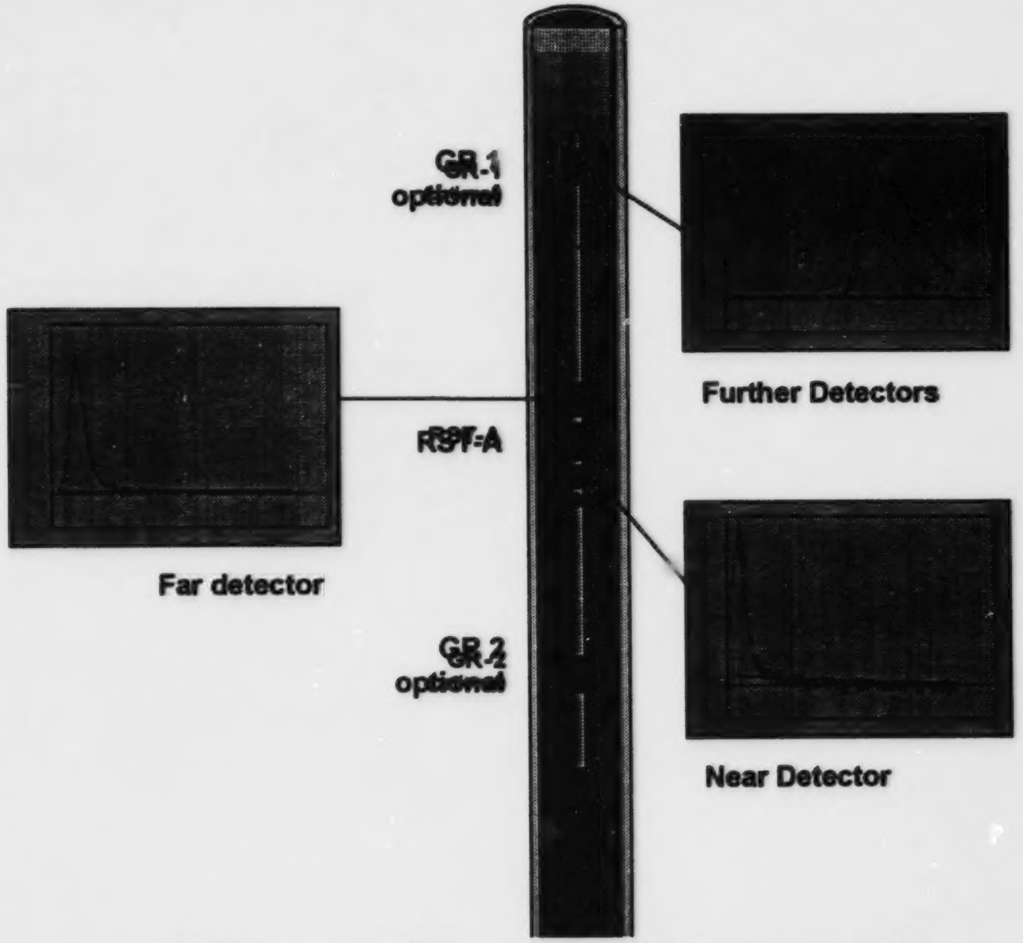
Water Flow Log

Method


GR-1
optional
RST-A
GR-2
optional
Further Detectors
Near Detector
Far detector

$^{16}O + n \rightarrow {}^{16}N + p \rightarrow {}^{16}O^{*} + \beta \rightarrow {}^{16}O + \gamma$

Half Life ~7.1s

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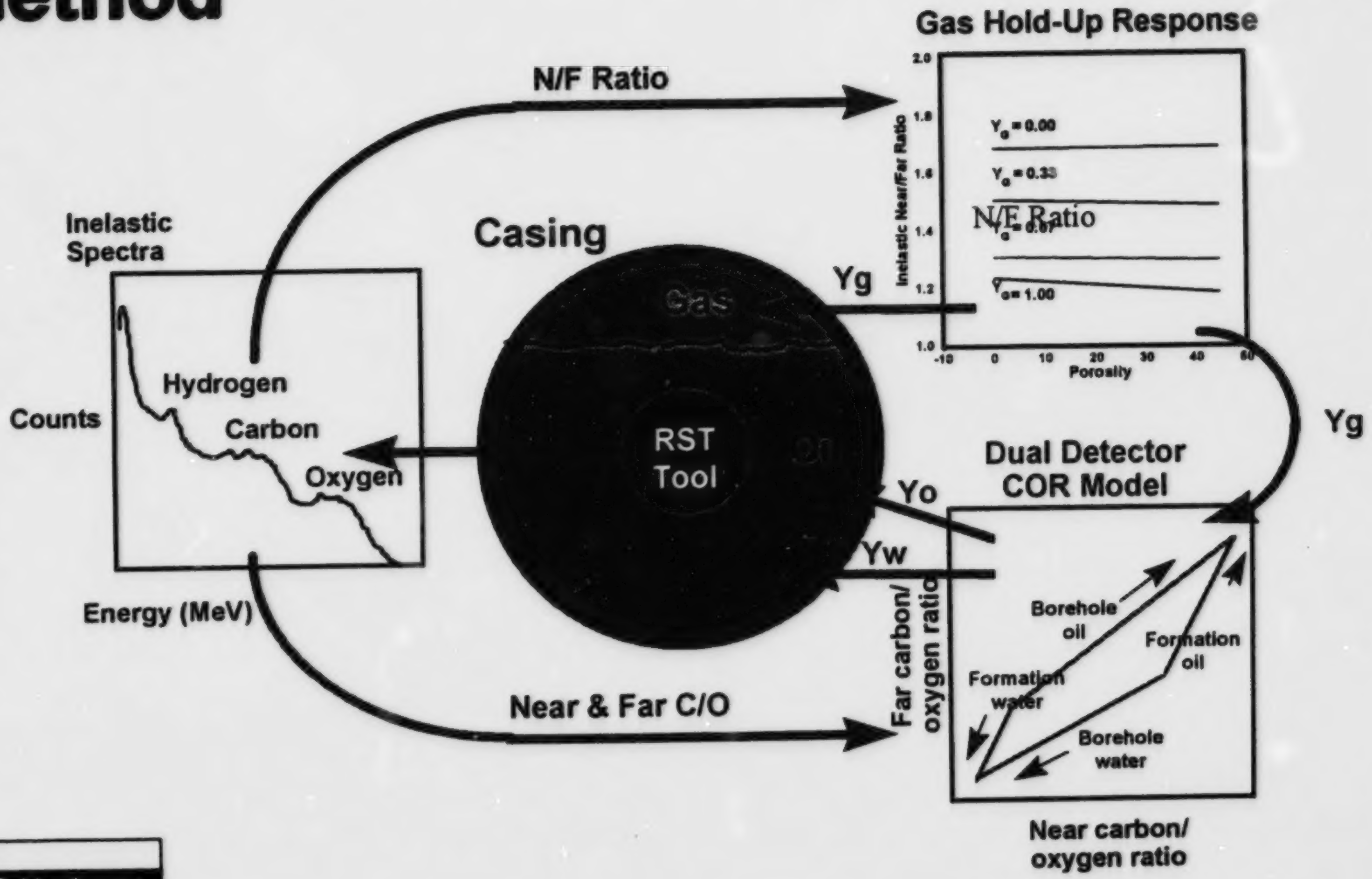
Three Phase Hold-up

Method



Gas Hold-Up Response

N/F Ratio

Inelastic Spectra

Casing

Counts

Hydrogen

Carbon

Oxygen

Energy (MeV)

RST Tool

Yg

Yo

Yw

Dual Detector COR Model

Near & Far C/O

Far carbon/ oxygen ratio

Near carbon/ oxygen ratio

Borehole oil

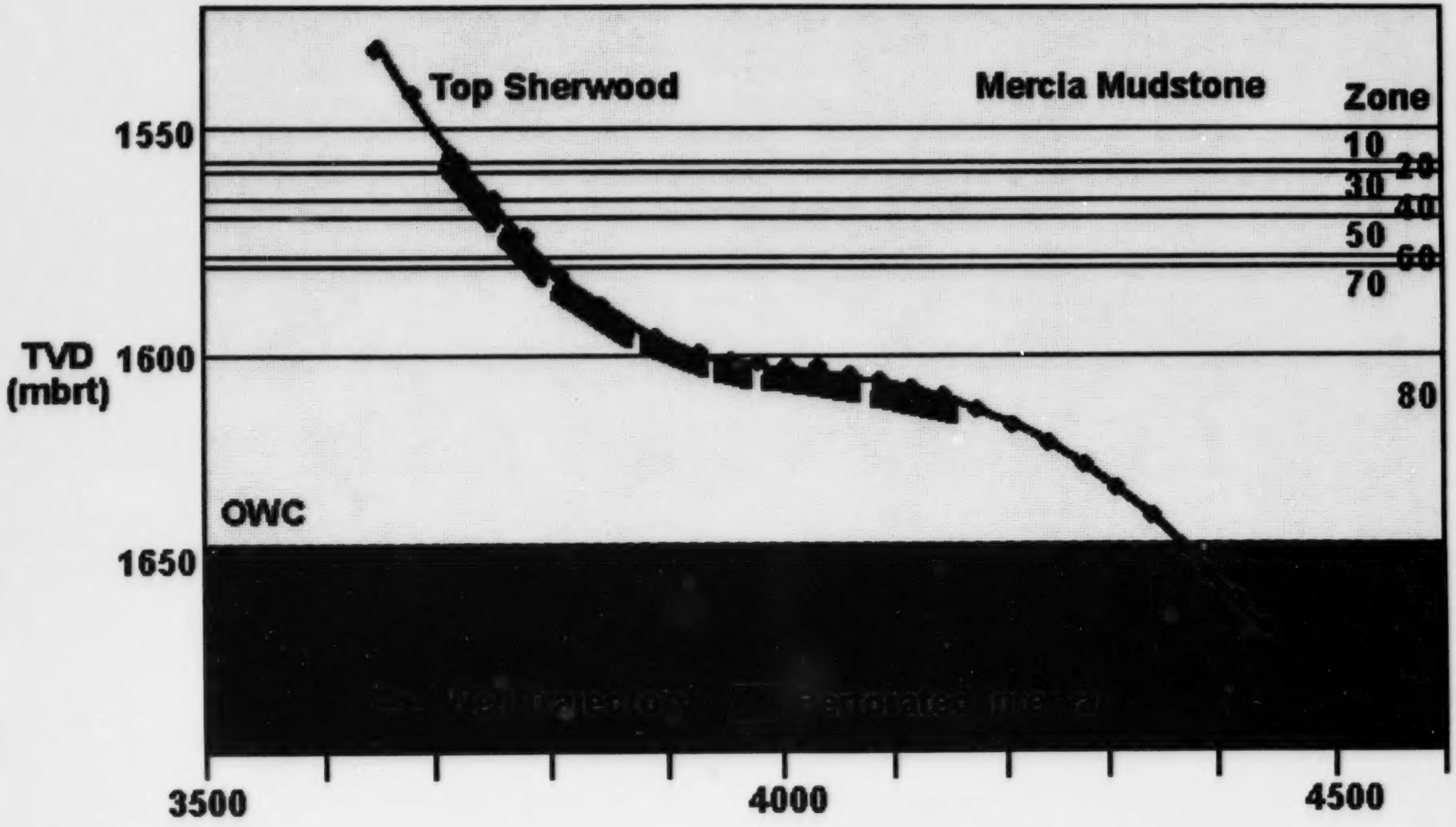
Formation oil

Formation water

Borehole water

Gas
Oil
2.0
1.8
1.6
1.4
1.2
1.0
Inelastic Near/Far Ratio
$Y_g = 0.00$
$Y_g = 0.33$
$Y_g = 0.67$
$Y_g = 1.00$
-10
0
10
20
30
40
50
Porosity

Horizontal Well Evaluation Example 1



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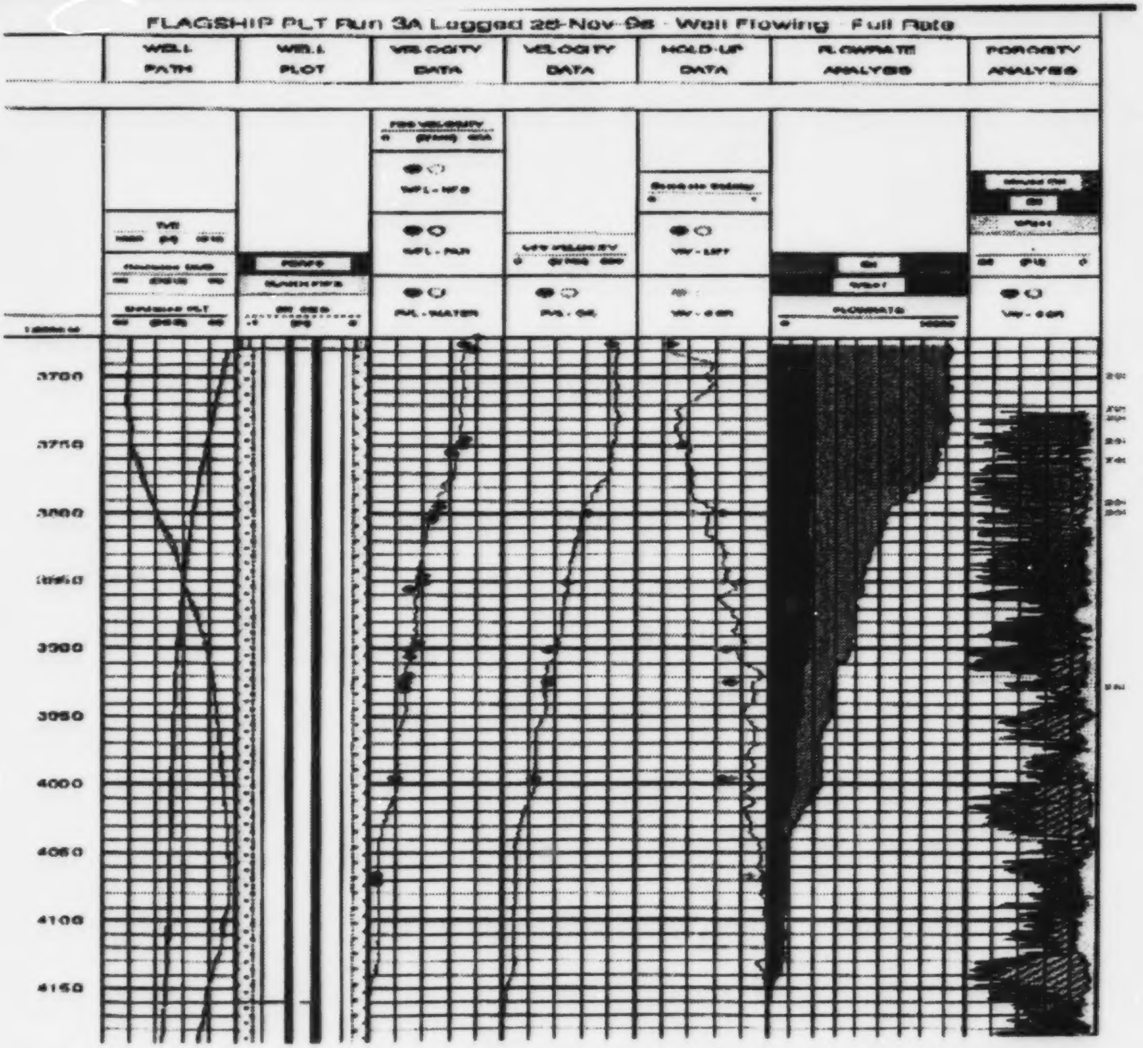
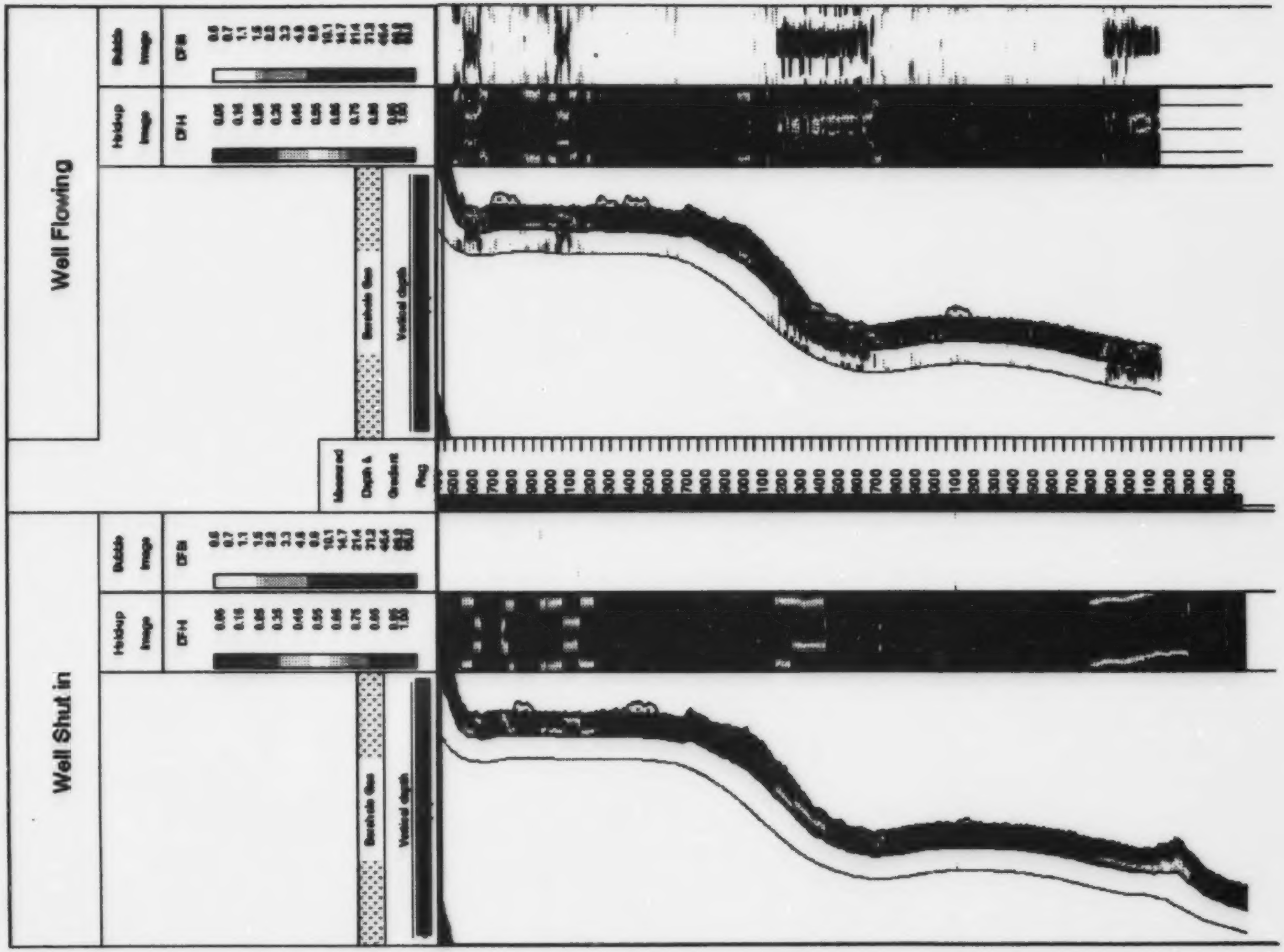
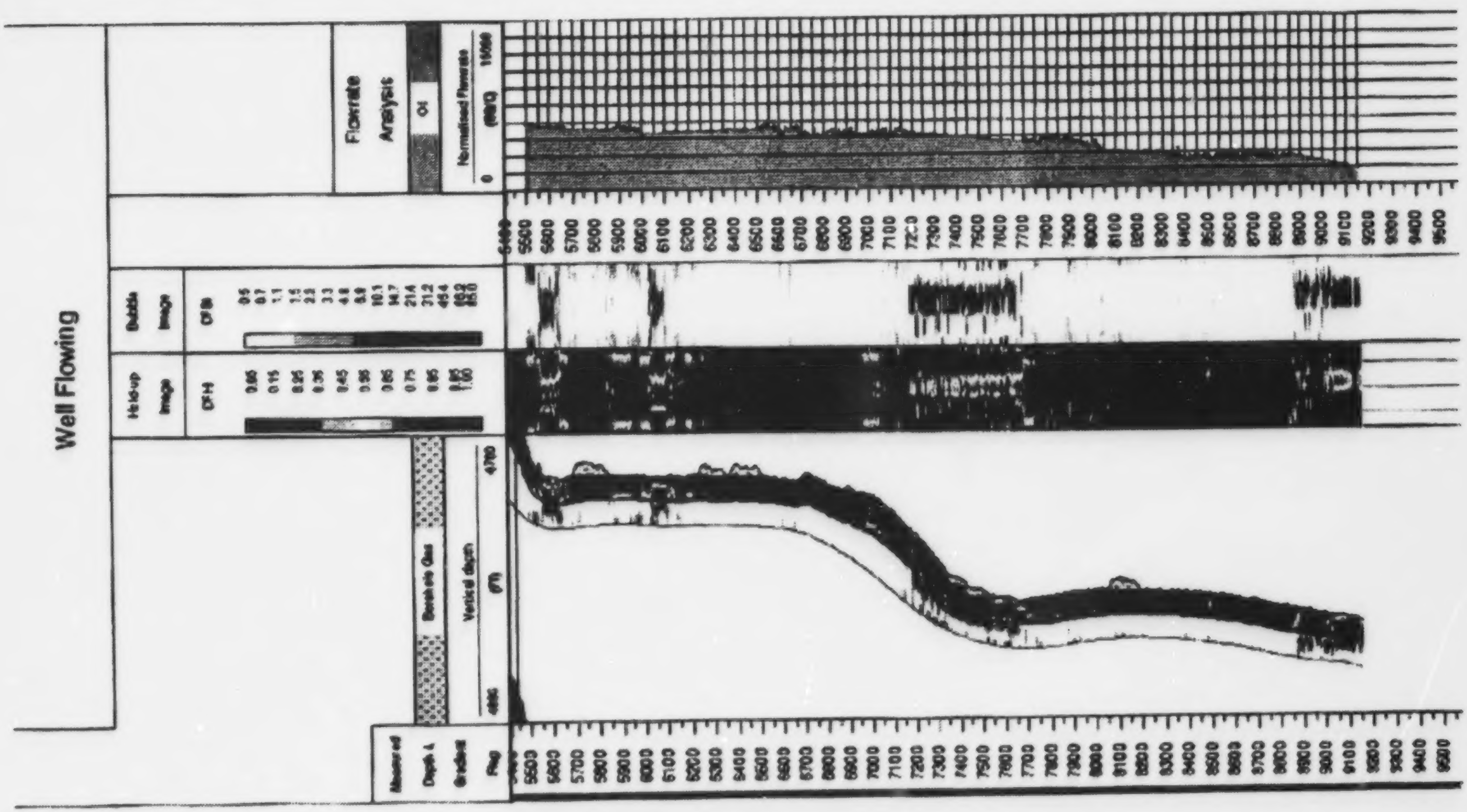
Wytch Farm Well F18 Composite Log



Flagship Example Barefoot carbonate well, 9.4" hole size



Horizontal Well Evaluation Example 2



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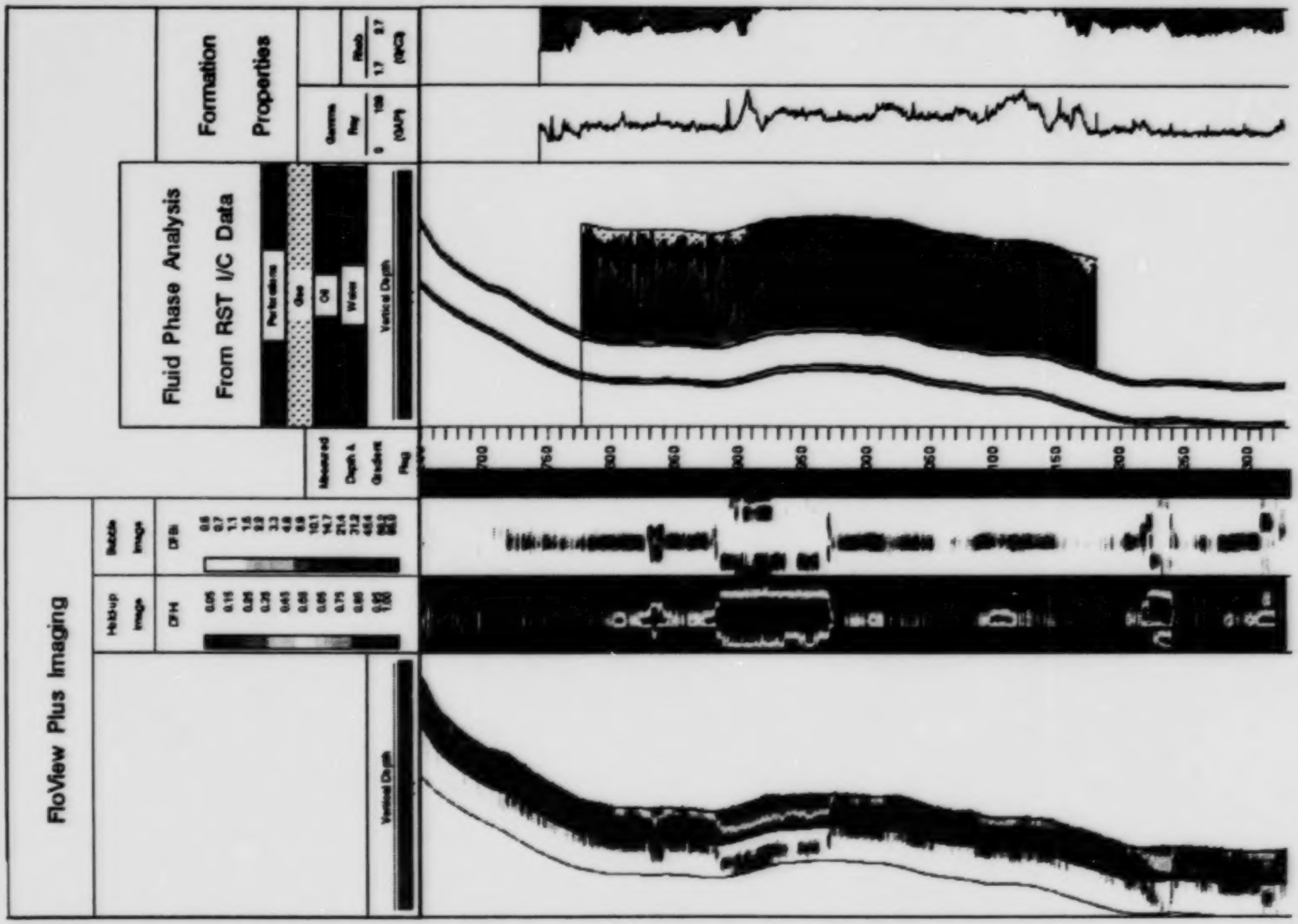
Flagship Example Three-phase production in a 4.5" cased hole



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O

Enhanced Recovery with Crosswell Imaging

Bruce P. Marion
TomoSeis Incorporated

Enhanced Recovery with Crosswell Imaging

Interwell Information

Despite the presence of closely spaced wells in older fields that are candidates for enhanced recovery, with associated data, the interwell region remains a frontier, poorly understood and lacking adequate information to optimally apply enhanced recovery strategies. 3-D surface seismic data in many heterogeneous reservoirs lacks the resolution to characterize structure or monitor property changes at the scale that controls flow and enhanced recovery. The result is that heterogeneous reservoirs have recovered only 15 to 20 percent of original oil in place. The principal barrier to enhanced recovery is an inadequate description of the heterogeneities between the wells.

Seismic images between wells at the resolution of well logs, from crosswell seismic data, are beginning to demonstrate their value in filling the information void in the interwell frontier. Seismic velocity and seismic character, at the unprecedented resolution available from crosswell, can be used to measure and monitor changes in fluids, reservoir pressure, oil saturation and porosity. Detailed structural characterization of the reservoir provides information to update geologic models and ultimately reserve estimates.

Enhanced Recovery Economics

With cost-effective crosswell services providing acquisition and processing of a crosswell profile (survey between a pair of wellbores) for $15,000 to $30,000, the method is being considered for use in a variety of enhanced recovery and well placement applications. The quantum step in reservoir information provided by crosswell seismic imaging makes crosswell data an ideal candidate to leverage planned major investments in redeveloping a field. An incremental investment in crosswell information leverages the value of a 3-D data set by calibrating the lower-resolution, higher areal coverage surface seismic data to the specific reservoir heterogeneities revealed in log-scale imaging. Enhanced geologic insight into a reservoir can optimize an initial secondary recovery plan, providing a potential increment in recovery from the planned investment. Monitoring and diagnostic surveys, using crosswell to track pressure fronts or monitor changes in fluid content, allow for performance evaluation and run-time improvements in CO_2, water or steam floods. Ultimately, improved reservoir characterization with crosswell seismic imaging will optimize reserve estimates and planning of field redevelopment strategies.

Leverage Horizontal Drilling

If additional wells are planned in redeveloping an older field, crosswell can also be a tool for planning strategic infill drilling. The optimum part of the field for further infill can be selected based on recoverable reserves in previously undetected structures seen with log-scale imaging. If horizontal drilling is contemplated, crosswell imaging can be used to precisely place the wellbore in high permeability zones as thin as 10 feet or less. An optimized well track will lead to enhanced recovery from the horizontal wellbore, making the use of log-scale information from crosswell a cost-effective decision. Formation evaluation measurement-while-drilling (FEMWD) logs will prove more valuable when the initial well track is selected using log-scale images that tie the wireline logs at the wellbore. Recently introduced sonic MWD tools may be especially effective in real-time tying of the horizontal wellbore to the crosswell-derived well track.

Geophysics for Engineers

Crosswell seismic is an emerging technology with proven and verifiable technical performance in older heterogeneous reservoirs. Crosswell will accelerate the adoption of geophysical methods into reservoir engineering applications as the economic benefits of the method are demonstrated on field-wide bases.

CO_2 Flood

Current crosswell equipment and data processing provide reliable performance at 40 acre well spacing and at greater spacing in selected situations. Closely spaced wells typical of CO_2 and steam flood projects are ideal candidates for crosswell seismic tracking of CO_2 and steam to aid in understanding and improving flood performance (Figure 1). An entire technical session at the 1996 Society of Exploration Geophysicists Annual Meeting, McElroy Reservoir Characterization (Harris, Wang, Lazaratos, et al), was devoted to a consortium project that demonstrated the detectability of CO_2 with crosswell methods. Crosswell information is collected in a baseline survey conducted prior to enhanced recovery operations. After injection of CO_2 begins, one or more crosswell surveys are conducted in the same wellbores for time lapse monitoring of changes in the reservoir due to injection. The color map (Figure 1) is an image of seismic velocity changes due to the presence of CO_2 and changes in injection pressure. Major changes are highlighted in red; no change is expressed in blue. Zonation of CO_2 into layers as thin as 5 to 10 feet allows for delineation of unswept zones, thief zones and vertical migration of CO_2. Subtle changes below the resolution limits of 4-D surface seismic are clearly discerned with crosswell reservoir monitoring. The underlying crosswell seismic traces show detailed reservoir structure as imaged prior to the start of CO_2 injection. Detailed reservoir characterization assists in flood planning. The color change just above 2850 feet near the production well is delineated by a terminating seismic event just above it. CO_2 streaks near the producer at 2950 and 2970 feet have associated terminating seismic events. Better planning using crosswell seismic has significant potential economic impact for enhanced recovery.

Pressure Mapping

One of the formation changes present in the CO_2 flood example is a change in reservoir effective pressure due to a change in the CO_2 injection pressure. Under most reservoir conditions, pressure changes cause a measurable change in seismic velocity, making crosswell seismic imaging an effective tool for pressure mapping. If performance is problematic in a specific area of a water or CO_2 flood, crosswell seismic can be used to diagnose the problem whether or not a baseline survey before enhanced recovery exists. If the effective pressure can be changed in the reservoir by adjusting injection pressure, a diagnostic survey can be performed by running a crosswell survey, changing the injection pressure and running a repeat survey to map the pressure change. With the diagnostic pressure mapping approach, existing enhanced recovery projects can be improved using the high-resolution information about flow in the reservoir from crosswell data.

Reservoir Characterization

Improved understanding of the complex geology in heterogeneous reservoirs is essential to optimizing an enhanced recovery program. Crosswell reflection images (Figure 2) reveal previously undetected heterogeneities and give geologists a new tool for enhanced reservoir characterization. Crosswell reflection images, like surface seismic images, can be used to reveal geologic structure. Features on the scale of 5 to 10 feet that would be invisible in a surface seismic section can be resolved. Larger features, such as carbonate reefs that may be detected but not accurately located with 3-D surface seismic data, can be pinpointed with crosswell reflection data. With rapid multi-profile data acquisition, crosswell reflection sections can be produced extending for thousands of feet with vertical resolution of a few feet. The reservoir can be further characterized in terms of formation properties such as porosity using crosswell-derived formation property maps (Figure 3). The relationship of seismic velocity to critical reservoir properties is known for many reservoirs based on laboratory measurements. With the petrophysical relationships, images are made of reservoir properties between wells

Calibrating 3-D Seismic

3-D seismic interpretation still faces difficult challenges in thin, heterogeneous reservoirs due to limited resolution. Interpretations can often be based on subtle character or amplitude changes sometimes present in only a few surface seismic traces. If the only points of control are existing wellbores, tying a reservoir feature such as subtle faulting to a particular 3-D seismic character change is difficult. Crosswell seismic data collected over a limited calibration area of a 3-D survey offer the unique ability to reliably and repeatably tie subtle heterogeneities to a surface seismic character change or attribute. Crosswell may be the bridge technology to rapidly move the benefits of 3-D seismic coverage into older fields.

Horizontal Drilling

A 1994 DOE survey of U.S. and Canadian operators using horizontal drilling cited inadequate reservoir description as the biggest contributor to economic failures in technically-successful horizontal wells. When in-place vertical wells are available, crosswell seismic imaging can provide information between the wells to establish the optimum well track to place the horizontal wellbore inside a high porosity zone over its full lateral extent. Because crosswell seismic data is logged and processed in depth, eliminating the time-depth uncertainty in surface seismic, a horizontal well track can be placed within a 10-foot thick reservoir zone (Figure 2).

Applying Crosswell Seismic

When an application for crosswell seismic is selected, the operation is conducted in several steps: survey planning, data acquisition, data processing and applications support.

Survey planning consists of determining the optimum set of logging parameters to obtain the required coverage of the target horizons at a minimum cost. In addition, planning is undertaken for specific wellbore conditions and well site operations. Data acquisition (Figure 4) consists of deploying a seismic source in one wellbore and multiple-level receiver systems in one or more adjacent wellbores. The receiver systems are deployed at a selected level in the planned logging interval. The source is then logged up through the designated source logging interval, typically a 1000 to 2000 foot interval, firing while in motion. The process is repeated for additional receiver locations. The total logging time for a set of simultaneously acquired profiles is typically 24 to 48 hours. The data is placed on log depth using production logging depth tie-in procedures.

Although more powerful sources are under development requiring specialized conveyance mechanisms, the most reliable, easy to use and cost-effective tools available today are wireline conveyed. As standard wireline tools (Figure 5), piezoelectric crosswell source and hydrophone receivers can be deployed in cased or open holes. The tools operate to well depths in excess of 15,000 feet, at temperatures to 150°C, using standard production cased hole pressure control equipment such as lubricators and grease injection. The source tool is 4-1/8" O.D. providing operation in 5-1/2" casing. The receiver tools are 1-11/16" O.D. Tools have been hardened for H_2S and CO_2 environments and are fluid-coupled like sonic logging tools, requiring the wellbore to have fluid in the logging interval: water, brine, kill mud or other fluids.

Following acquisition, the data are returned to the processing center for quick-turnaround seismic processing. The data are processed to produce two forms of display (Figure 4): the color velocity image and the surface-seismic-format reflection image. Log-scale interwell seismic data (Figure 6) adds to the rich volume of reservoir information, making possible a variety of consistency checks that validate a log-scale reservoir interpretation. Velocity images, plotted as a log, tie directly with sonic logs at the wellbore. Reflection images can be processed using seismic inversion to produce velocity values tying the velocity image and sonic log. Crosswell synthetic seismograms, produced from the sonic and density logs, provide a direct tie at the wellbore with the reflection section. The variety of consistency checks reduces the imaging uncertainty associated with surface seismic data.

Intuitive Interpretation

Overlays of velocity images and reflection sections aid in precisely delineating high porosity zones seen in the velocity image and outlined by reflection events. Amplitude changes in the reflection sections correspond to underlying velocity changes. Multiple-profile crosswell surveys provide additional consistency checks using the tie between adjacent images sharing a common well and the 3-D tie between images that cross the same feature such as a fault. Crosswell data are delivered both as a set of logs between the wells and as a seismic section to allow interpretation using existing interpretation systems.

A Tool for Today

In addition to current capabilities, a number of improvements have been undertaken by oil company researchers, service companies and equipment vendors to extend the applicability of crosswell seismic (Table I).

Table I. Crosswell Technology Enhancements

Technology Extension	Method
Operation at greater well spacing	Stronger borehole seismic sources
Extended shear-wave logging	3-component sources and receivers
Through-tubing receiver operation	Through production tubing, 1-11/16" hydrophone receiver systems
Faster operation in wells not requiring pressure control equipment	multi-level receivers with more than 10 levels using digital telemetry and fiber optic wireline

Technology is in place today to cost-effectively acquire and process log-scale interwell information. The challenge is to apply, characterize and calibrate this geophysical method in real-world enhanced recovery engineering applications.

Some of the advanced seismic technology described herein was developed with the assistance of Gas Research Institute and Department of Energy.

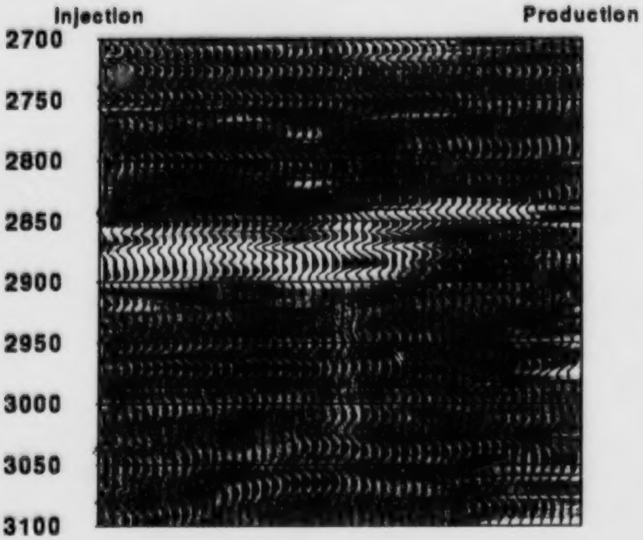

Figure 1. This color map is an image of seismic velocity changes resulting from the presence of CO_2 and changes in injection pressure. Major changes are highlighted in red; no change is expressed in blue.

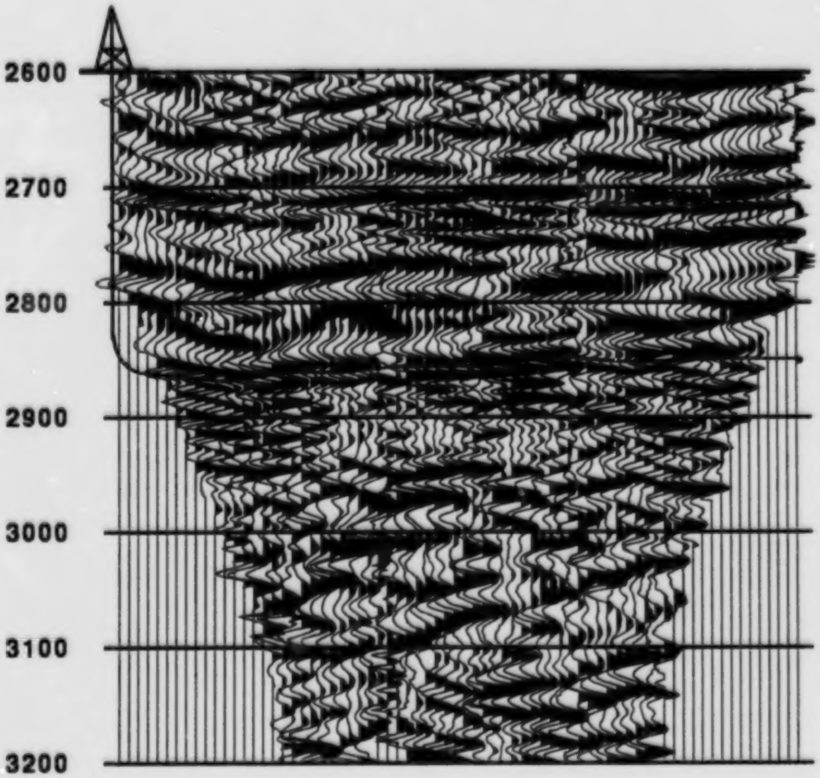

Figure 2. Crosswell reflection images reveal previously undetected heterogeneities and give geologists a new tool for enhanced reservoir characterization. Because crosswell seismic data is logged and processed in depth, a horizontal well track can be placed within a 10' thick reservoir zone.

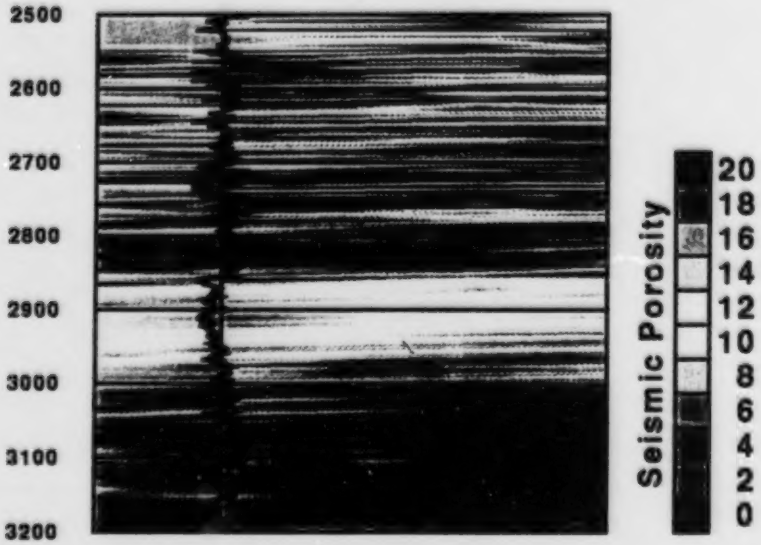

Figure 3. The reservoir can be further characterized in terms of formation properties such as porosity using crosswell-derived formation property maps.

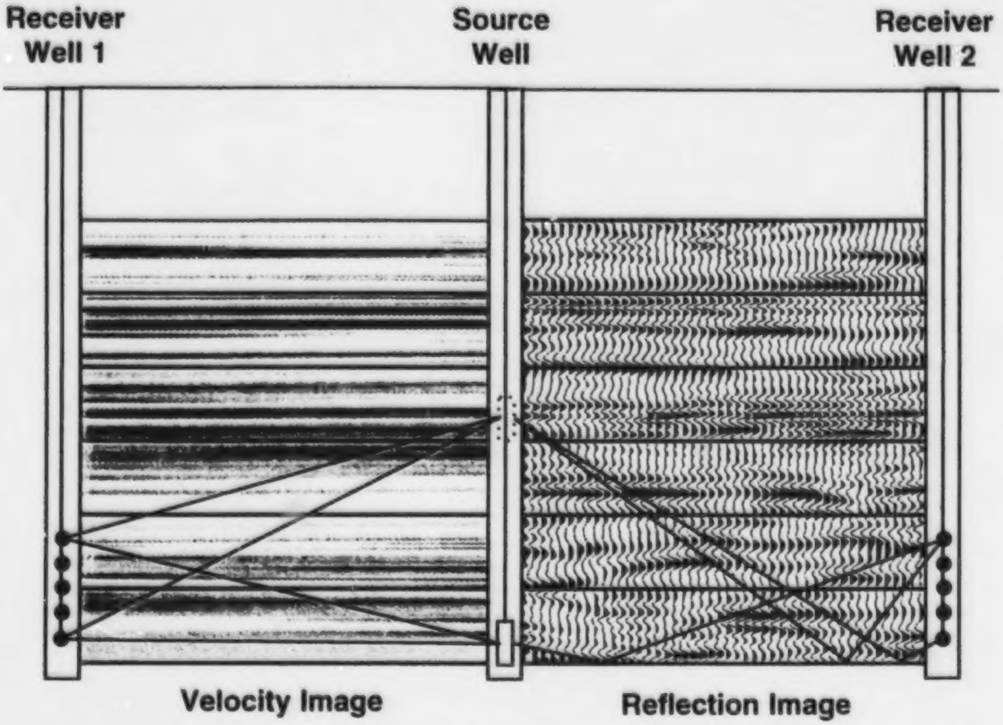
Receiver Well 1
Source Well
Receiver Well 2
Velocity Image
Reflection Image

Figure 4. Data acquisition consists of deploying a seismic source in one wellbore and multiple-level receiver systems in one or more adjacent wellbores. The data are processed to produce two forms of display: the color velocity image and the surface-seismic-format reflection image.

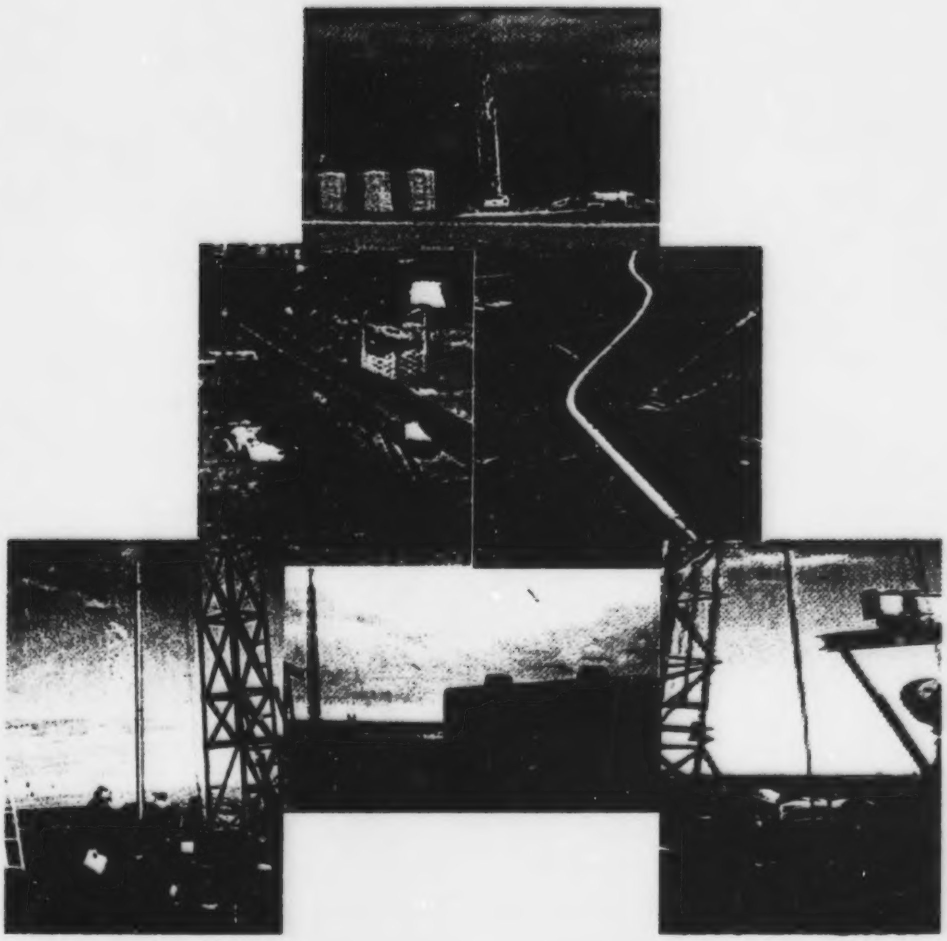

Figure 5. Crosswell operations using standard wireline tools.

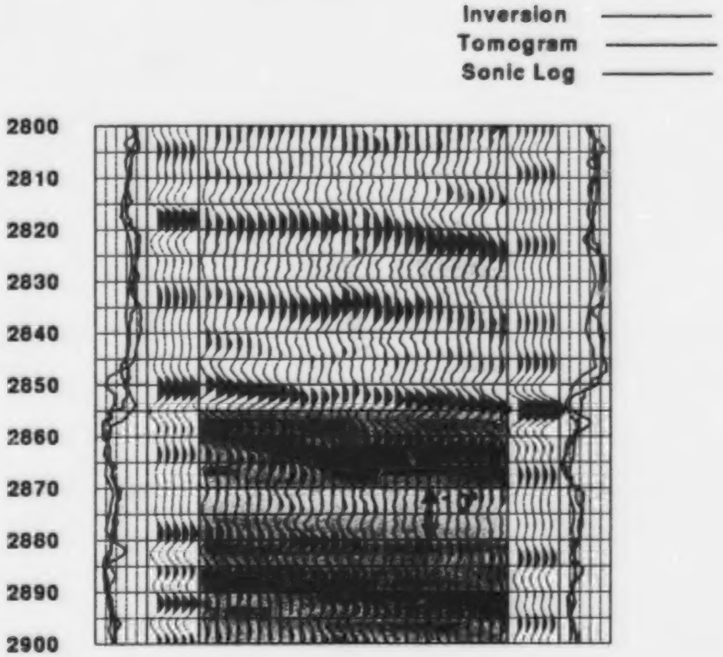

Figure 6. Log-scale interwell seismic data adds to the rich volume of reservoir information, making possible a variety of consistency checks that validate a log-scale reservoir interpretation.

P

Mississippian Carbonates of the Williston Basin: Aspects of the Geology We Don't Understand

John H. Lake
Lake Geological Services, Inc.

Mississippian Carbonates of the Williston Basin: Aspects of the Geology we don't understand.

John H. Lake, Lake Geological Services Inc., 1911 MacDonald Drive, Swift Current, Saskatchewan, Canada, S9H 1M1.

We have learned a great deal about Mississippian Stratigraphy of the Williston Basin. We also know quite a lot about the depositional environment of carbonate rocks within the basin. However, we know very little about the shallow and deep burial history, diagenesis, porosity development and anhydrite plugging which has occurred since burial. We need models to explain and predict porosity trends similar to those developed for facies distribution of the sediments.

The fundamental fact is that the Mississippian of the Williston Basin was deposited as an Epeiric Sea, with carbonate facies extending basinward for tens of miles because of the extremely low angle dip of the basin. The Williston Basin differs from the Michigan and Illinois Basins in not developing the deeper water, higher energy facies. The shallow nature of the basin is probably due to the low tectonic movement on the northeast side of the Trans-Continental Arch, in contrast to the other two.

Considerable confusion results from the various carbonate facies because of a tendency to contain a diversity of microscopic rounded allochems including abraded crinoids, Ortonella (Dasyclad/Blue-Green Algae; Wray, 1977), fecal pellets, coated pellets, oolites and oncolites. Fecal pellets are the nucleii for most coated pellets, oncolites and oolites; the oncolites are lower agitation energy variety and exceed the 2mm diameter cutoff for oolites (Flugel, 1986). Each formed as a direct response to agitation and wave energy/water depth.

We must be careful not to use facies as time markers across the basin for several reasons. The argillaceous markers (State A Marker. Sherwood Argillaceous Marker, etc.) are not particularly good time lines. They were deposited as argillaceous muds adjacent to sabkha margins in regressive seas. They were also dolomitized upon exposure and often remain as limestone in more basinal settings. We ignore the fact that facies have finite limits because of water depth and the stage of transgression/regression and distribution of stepping shelves. Hence, it is difficult to imagine that we are even talking about the same time period for individual formations all the way across the basin. In fact, often we are misinterpreting time with facies distribution.

The Mississippian cyclic sedimentation of southern Saskatchewan gives us a predictable tool for hydrocarbon exploration, as evidenced by the Midale beds. The beds deepen upwards (marine transgression) to the middle of the Midale, then subsequently shallow again. There is no unconformity between the Midale carbonates and overlying Midale evaporites. Rather, this is a natural progression to shallower conditions , including tidal flat sabkha evaporites and eventual exposure at the top. Hence the maximum flooding surface occurs where the cycles reverse from transgressive to regressive seas (ie. highest energy environment and hence best potential reservoirs). We are confused and spent a lot of time picking tops for the obvious transition from carbonate to evaporite deposition and ignore the all important maximum flooding surface.

Many workers have recognized the shrinking nature of the Williston Basin with time (Hendricks, 1988) and significant shoreline trends (Potter, 1995) and have made significant contributions to our knowledge. Few have recognized tectonic movement during and after deposition (Redly and Hainal, 1995). The basin appears relatively quiet during Alida deposition but is riddled with unconformities in Frobisher (ie. Stoughton, Sherwood, Halbrite, Huntoon, Hastings) and Midale time (Midale Vuggy-Midale Marly contact) in the major southeast Saskatchewan pools.

The Missippian porosity in most Saskatchewan pools is secondary in nature. We encounter some moldic porosity development, but most of the producing reservoirs contain vuggy porosity. The vuggy porosity has vertical limits and often extends for great distances. Porosity development is not facies restricted and goes from oncolite grainstone beachrock to ostracod calcisphere restricted lagoonal mudstone facies. The porosity may have developed 1)early from acidic rainwater in rocks above the water table (Vadose), 2)from dissolution by groundwater derived from the Lower Watrous Red Beds, or 3)from dissolution by deep burial fluids. The origin and timing of porosity development needs to be modelled further in order to predict trends and exploration paths.

Timing and the source of anhydrite plugging of the porosity is very poorly understood. We often encounter alternating interbedded anhydrite plugged and porous beds, suggesting lateral migration of the anhydrite. Dehydration of gypsum may force the waters down dip to create this phenomenon. An alternate possibility is the regressive sea created evaporitic conditions in the shallow facies adjacent to the sabkha margin and precipitated anhydrite in the underlying porous beds. This would explain the alternating plugged and porous beds. Our understanding of this phenomenon is poorly understood. The metasomatic anhydrite (dark brown with fluid inclusion containing hydrocarbons) is considered late stage and deep burial in origin (Kendall and Walters, 1978). It is commonly associated with very restricted lagoonal muds with Ortonella algae, and represents the updip facies trap of both the metasomatic anhydrite and the hydrocarbons.

The timing of both porosity enhancement and anhydrite infill are not yet resolved. We require a thorough understanding of mechanism and timing to develop a predictable tool for reducing exploration risk.

Acknowledgements;
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(Regina). Thanks to Dr. Don Kent for many stimulating conversations on Mississippian geology of southeast Saskatchewan.

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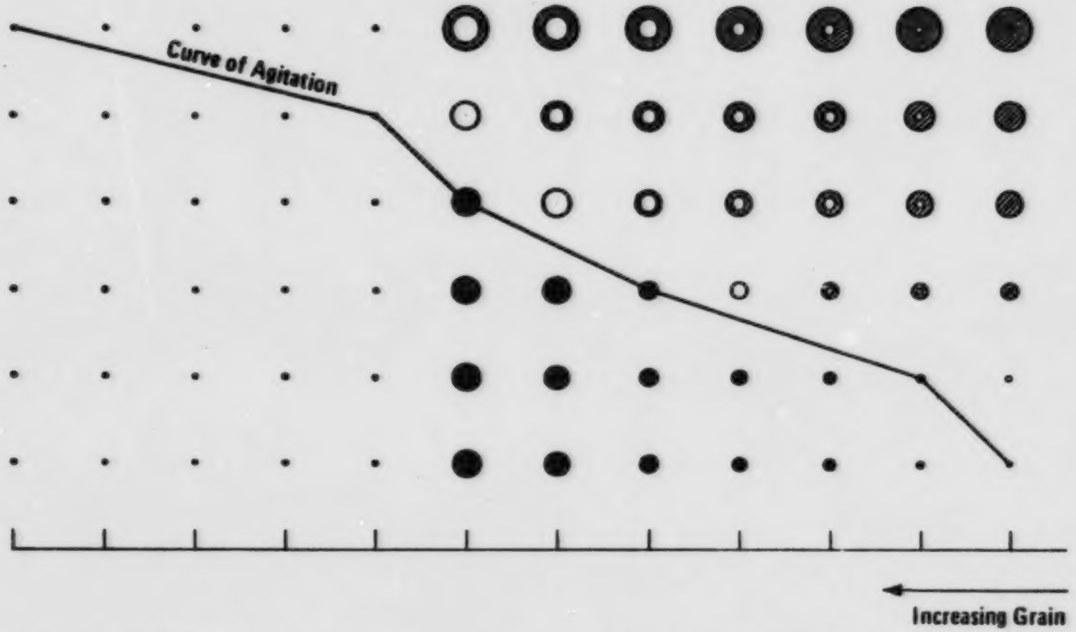
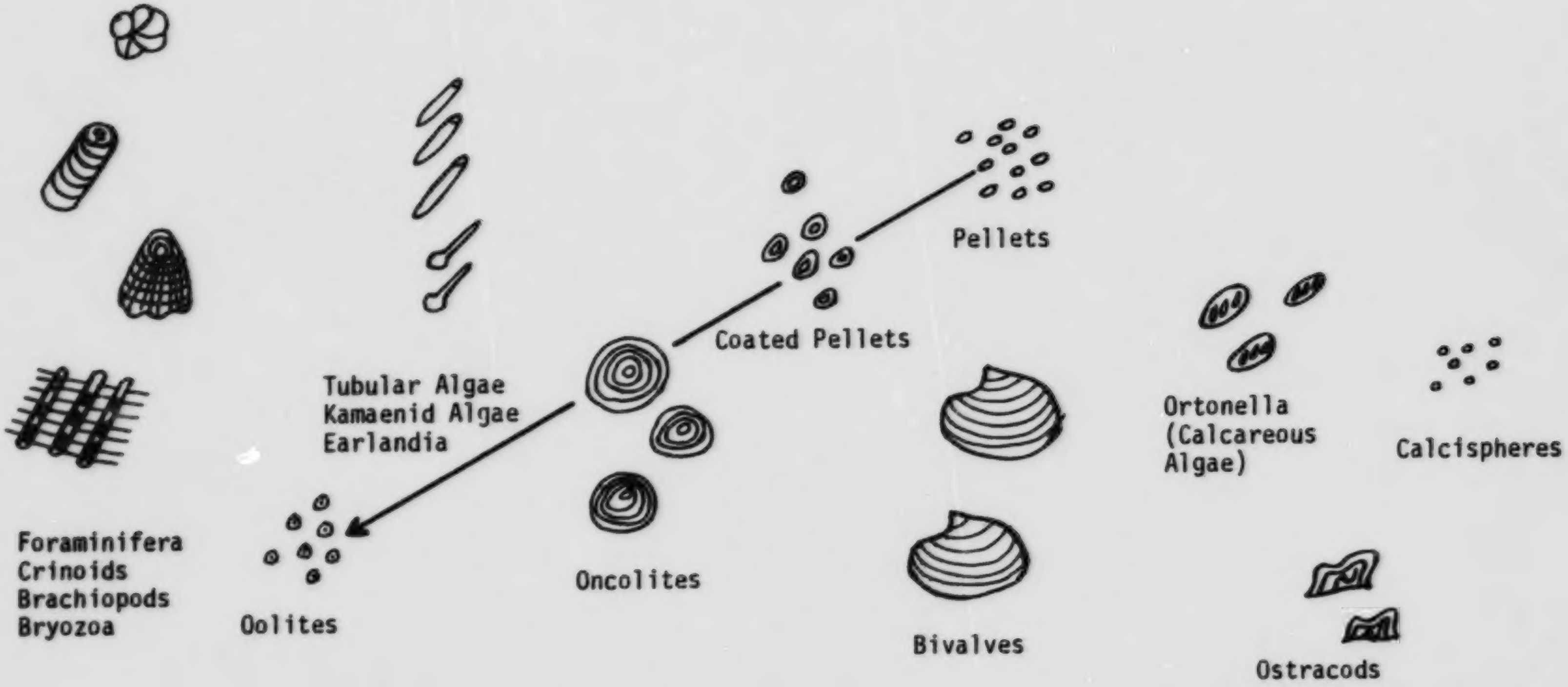
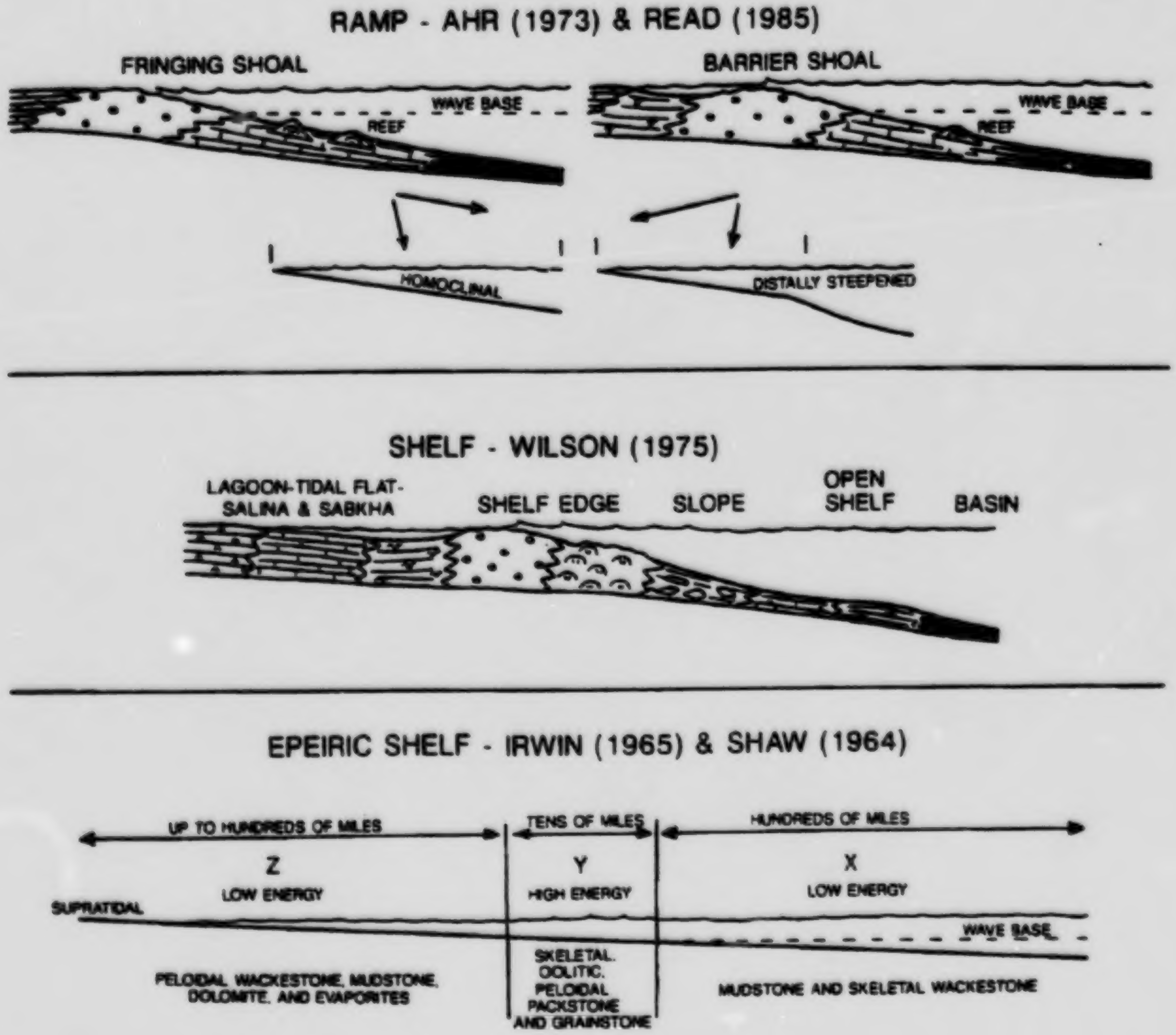

Curve of Agitation
Increasing Grain

Fig. 20. Relationship between water energy, particle size and laminae thickness after Car (1960). Black circles: non-ooids; open circles: superficial ooids; circles with cross-hatc signature: normal ooides

Graph illustrates the gradation from oncolites to oolites with increasing agitation. (Flugel, 1982).


Foraminifera
Crinoids
Brachiopods
Bryozoa
Tubular Algae
Kamaenid Algae
Earlandia
Oolites
Oncolites
Coated Pellets
Pellets
Bivalves
Ortonella
(Calcareous
Algae)
Ostracods
Calcispheres

Examples of diverse variability of allochems throughout Mississippian shallow water carbonates of the Williston Basin. The coated pellets, oncolites and oolites all have pellets for their nucleii. The similar size of the spherical allochems makes them difficult to identify in hand sample.



RAMP - AHR (1973) & READ (1985)

FRINGING SHOAL
BARRIER SHOAL
WAVE BASE
REEF
WAVE BASE
REEF
HOMOCLINAL
DISTALLY STEEPENED

SHELF - WILSON (1975)

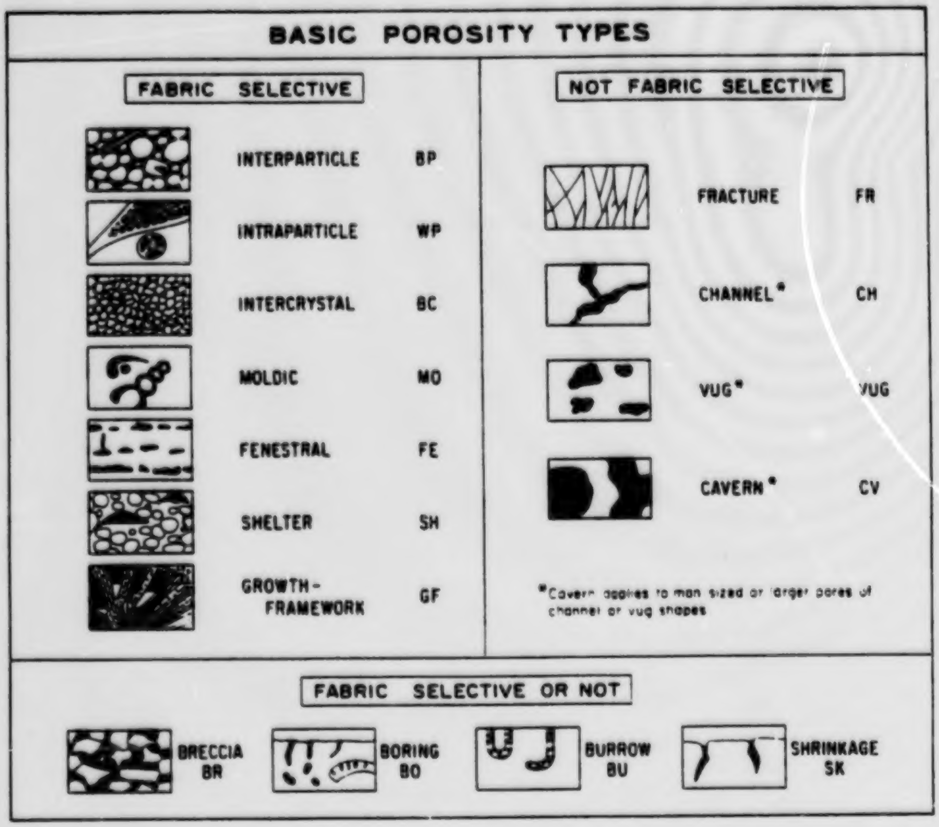
LAGOON-TIDAL FLAT-
SALINA & SABKHA
SHELF EDGE
SLOPE
OPEN
SHELF
BASIN

EPEIRIC SHELF - IRWIN (1965) & SHAW (1964)

UP TO HUNDREDS OF MILES
TENS OF MILES
HUNDREDS OF MILES
Z
LOW ENERGY
Y
HIGH ENERGY
X
LOW ENERGY
SUPRATIDAL
WAVE BASE
PELOIDAL WACKESTONE, MUDSTONE,
DOLOMITE, AND EVAPORITES
SKELETAL,
OOLITIC,
PELOIDAL
PACKSTONE
AND GRAINSTONE
MUDSTONE AND SKELETAL WACKESTONE

Figure 1. Standard facies models of ramps, rimmed shelves, and epeiric seas are static representations of carbonate platforms.

Handford and Loucks, 1993.


BASIC POROSITY TYPES
FABRIC SELECTIVE
INTERPARTICLE BP
INTRAPARTICLE WP
INTERCRYSTAL BC
MOLDIC MO
FENESTRAL FE
SHELTER SH
GROWTH-FRAMEWORK GF
NOT FABRIC SELECTIVE
FRACTURE FR
CHANNEL* CH
VUG* VUG
CAVERN* CV
*Cavern applies to man sized or larger pores of channel or vug shapes
FABRIC SELECTIVE OR NOT
BRECCIA BR
BORING BO
BURROW BU
SHRINKAGE SK

Choquette and Pray, 1970

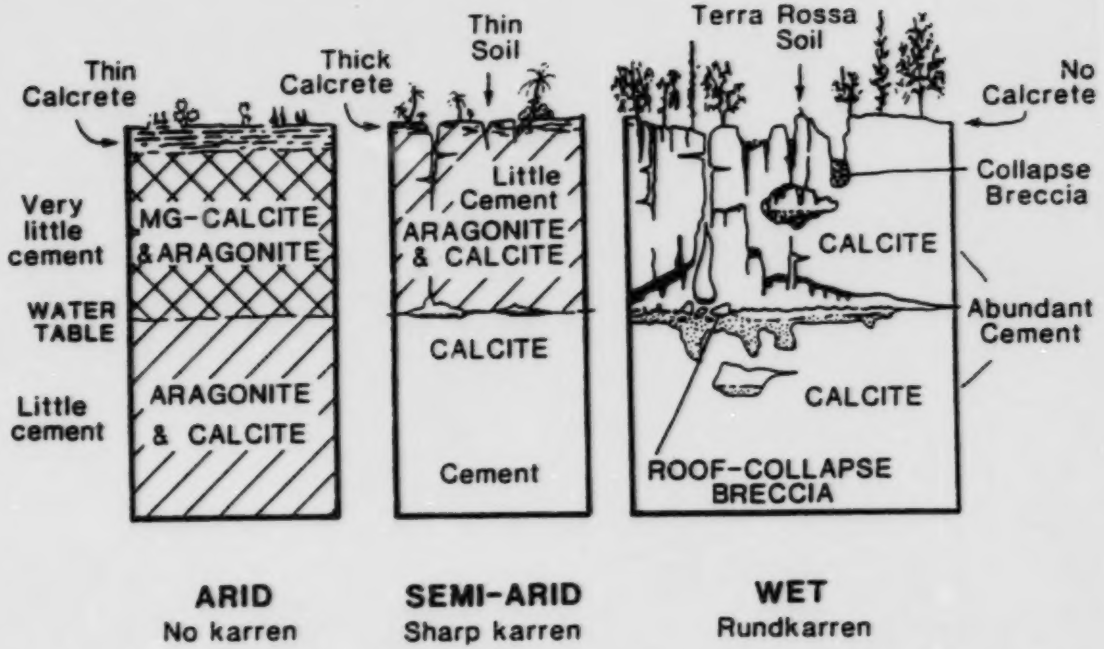

Thin Calcrete
Thick Calcrete
Thin Soil
Terra Rossa Soil
No Calcrete
Very little cement
WATER TABLE
Little cement
MG-CALCITE &ARAGONITE
ARAGONITE & CALCITE
Little Cement
ARAGONITE & CALCITE
CALCITE
Cement
Collapse Breccia
CALCITE
Abundant Cement
CALCITE
ROOF-COLLAPSE BRECCIA
ARID
No karren
SEMI-ARID
Sharp karren
WET
Rundkarren

FIGURE 3. A diagram showing common karst features associated with different climatic conditions. Modified from James and Choquette (1984).

Choquette and James, 1988

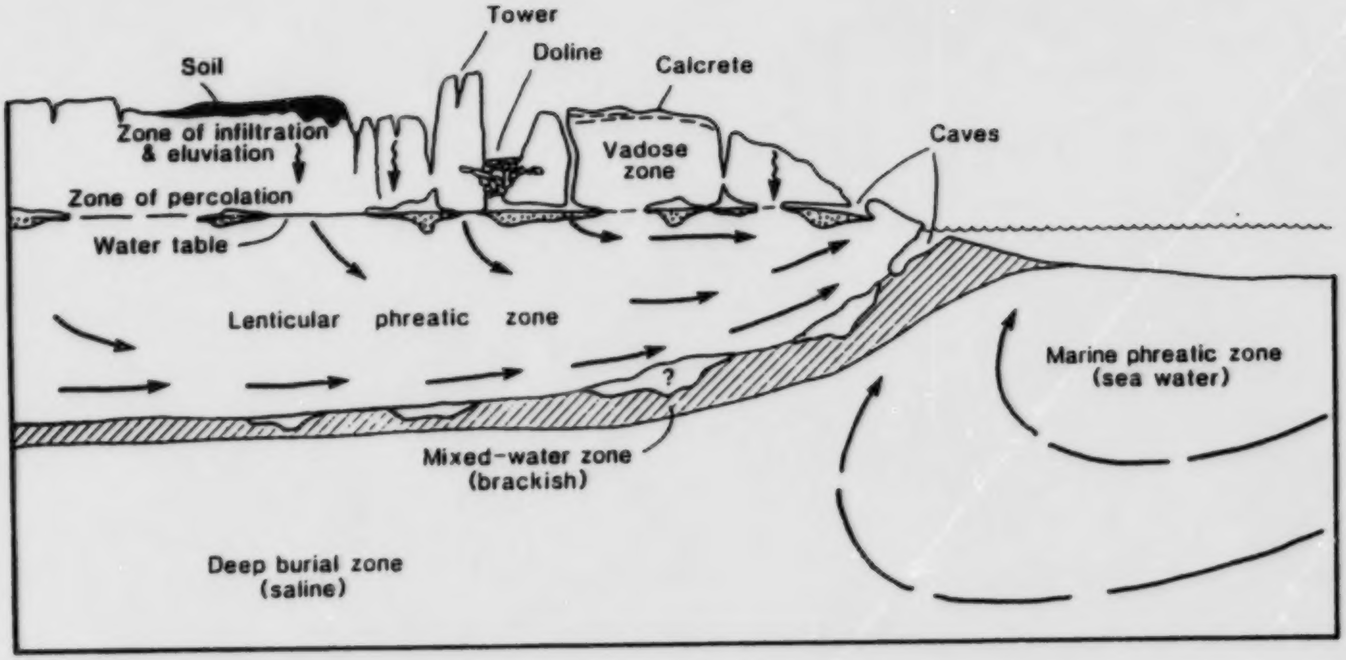
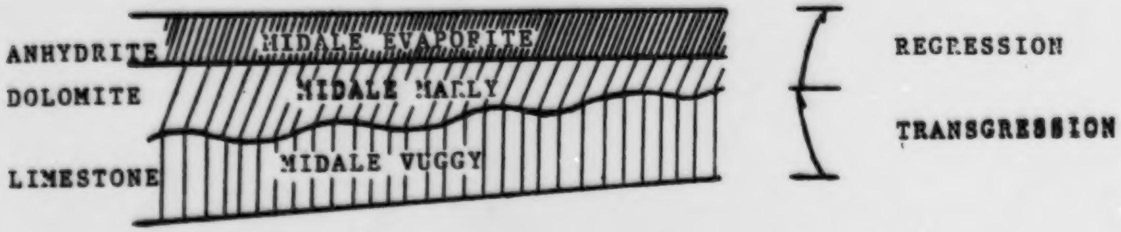

Tower
Doline
Soil
Calcrete
Zone of infiltration & eluviation
Vadose zone
Caves
Zone of percolation
Water table
Lenticular phreatic zone
Marine phreatic zone (sea water)
?
Mixed-water zone (brackish)
Deep burial zone (saline)

FIGURE 1. A diagram showing the general elements and hydrology of a karst terrane developed on recently deposited carbonates adjoining the sea.

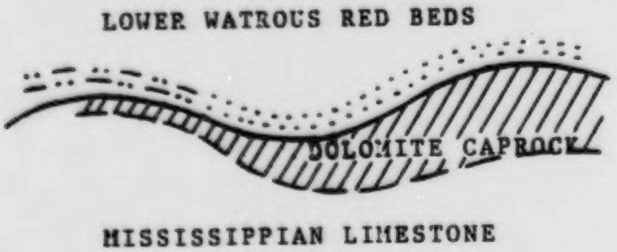
Choquette and James, 1988

MODEL FOR MIDALE BEDS DEPOSITION


ANHYDRITE
MIDALE EVAPORITE
DOLOMITE
MIDALE MARLY
LIMESTONE
MIDALE VUGGY
REGRESSION
TRANSGRESSION

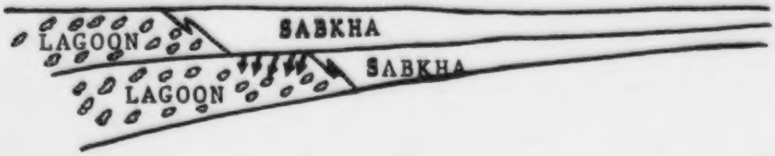
The highest energy environment of deposition in the Midale occurs at the point of maximum transgression (Top of Midale Vuggy). The Midale Midale Marly and Midale Evaporite represents a continuous regression with ultimate sabkha deposition. The Midale Marly is dolomitized from numerous exposures and fresh water mixing.

MODEL FOR MISSISSIPPIAN DOLOMITE CAPROCK THICKNESS VARIATION.

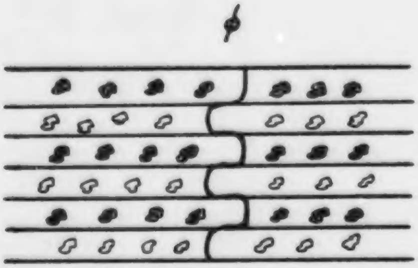

LOWER WATROUS RED BEDS
DOLOMITE CAPROCK
MISSISSIPPIAN LIMESTONE

The dolomite caprock is formed by Lower Watrous Mg- and $CaSO_4$-rich ground waters being forced into porous Mississippian carbonate after burial. Silty and argillaceous facies Lower Watrous are less permeable than sand and restrict downward fluid migration.

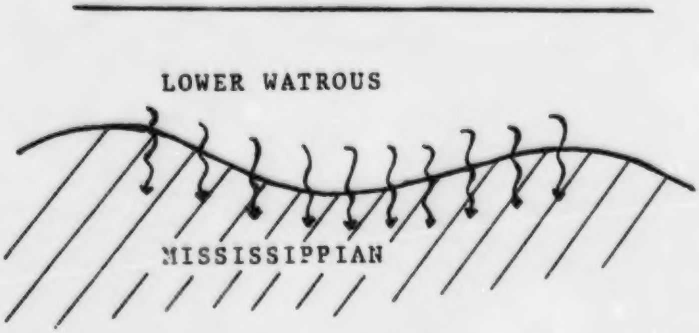
Anhydrite Infill of Porosity


LAGOON
SABKHA
SABKHA
LAGOON

During Marine Regressions, overstepping Sabkha supplies $CaSO_4$-rich fluids to underlying lagoonal carbonates.

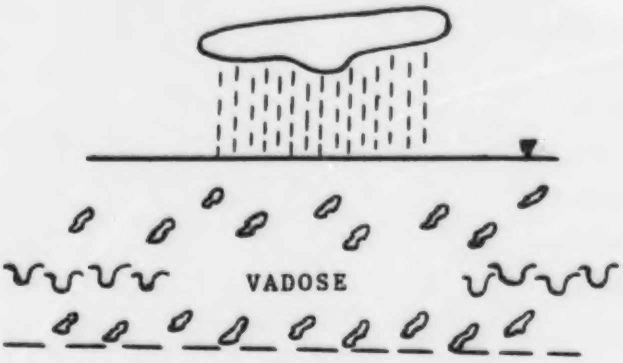


Interbedded porous and anhydrite-plugged beds suggests that $CaSO_4$-rich fluids migrated laterally.


LOWER WATROUS
MISSISSIPPIAN

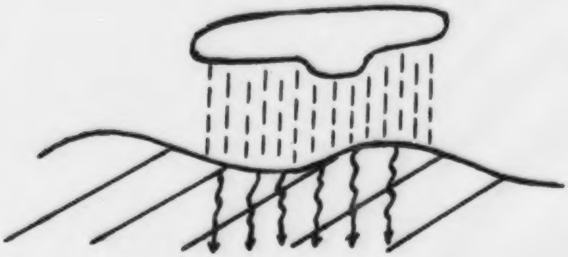
Post-burial dewatering of Lower Watrous Red Beds supplies $CaSO_4$-rich fluids. These waters are also Mg-rich and create the dolomite caprock.

ALTERNATE MODELS OF SECONDARY POROSITY DEVELOPMENT.

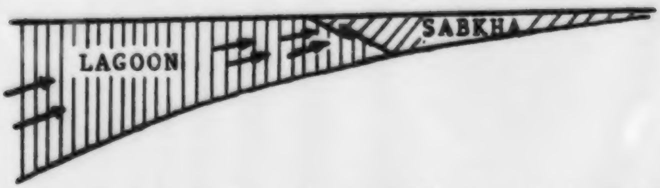


PHREATIC

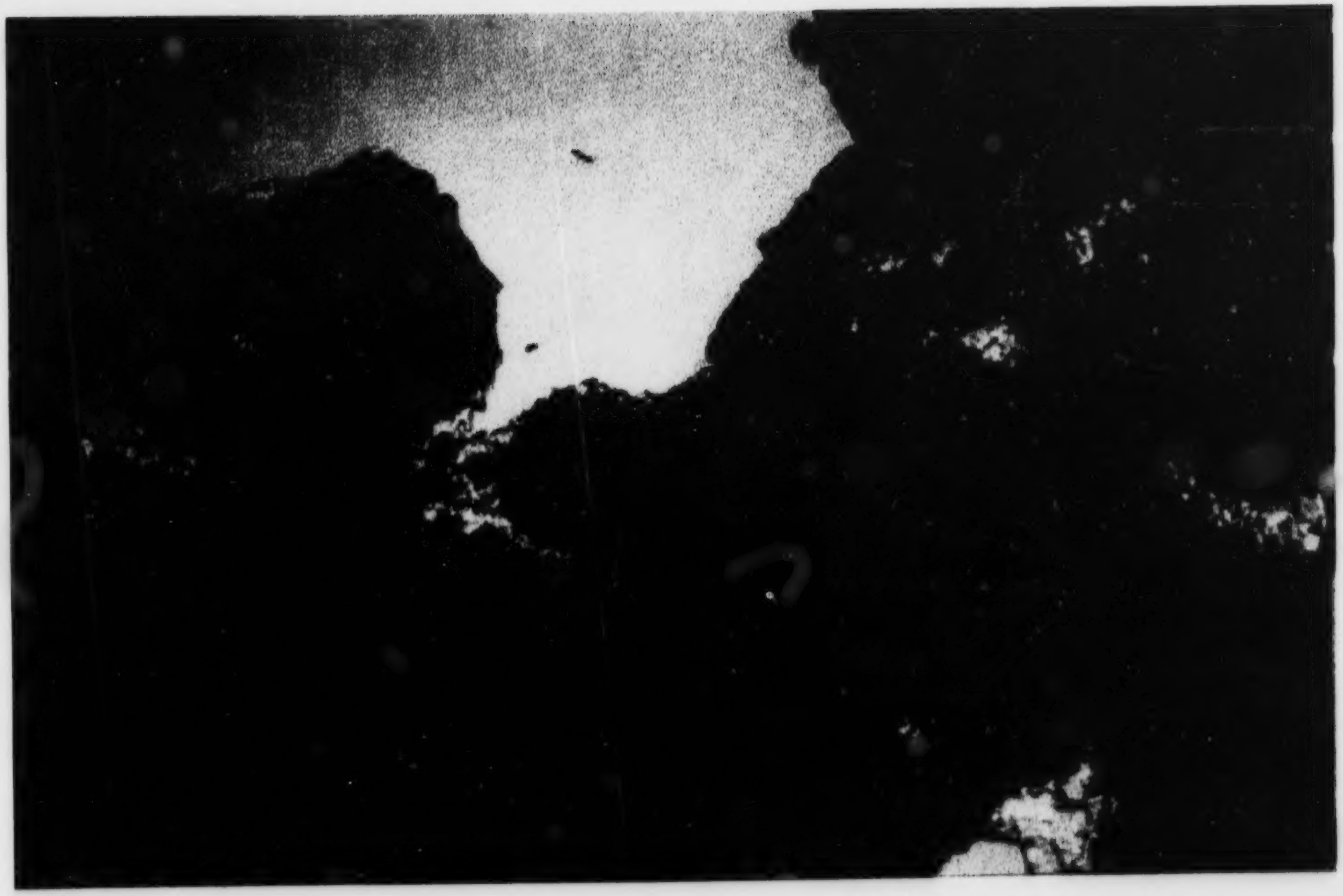
Shallow burial/uplift with acid rainwater-enhanced porosity development. Most intense vuggy porosity developed in lagoonal muds and oncolite facies. Deeper water facies commonly develop moldic porosity.



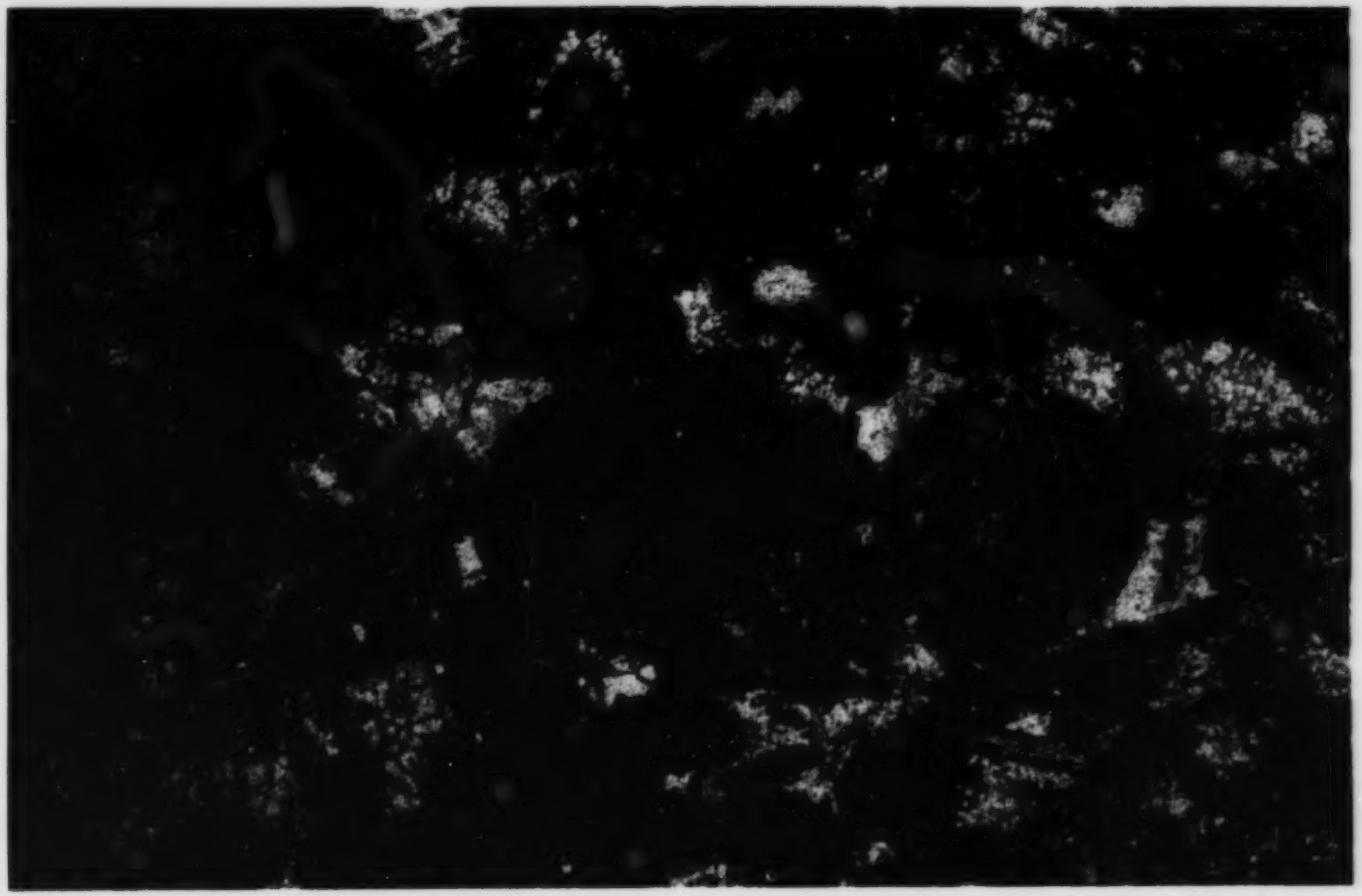
Post-Mississippian erosion and dissolution by acid groundwater



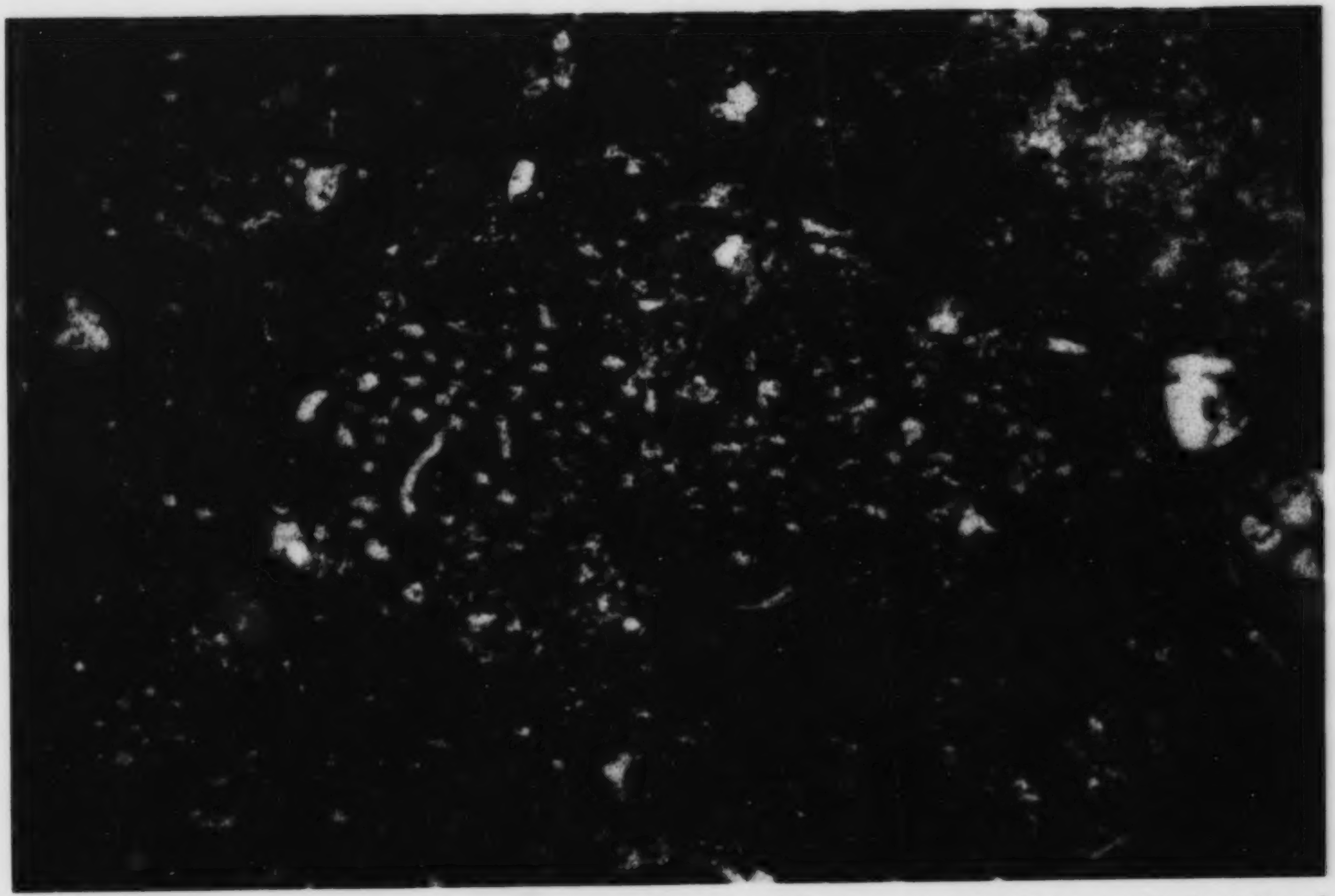
Deep burial fluids migrate updip to structural or stratigraphic trap. Water acidity created by H_2S-rich fluids motivated to try escape.



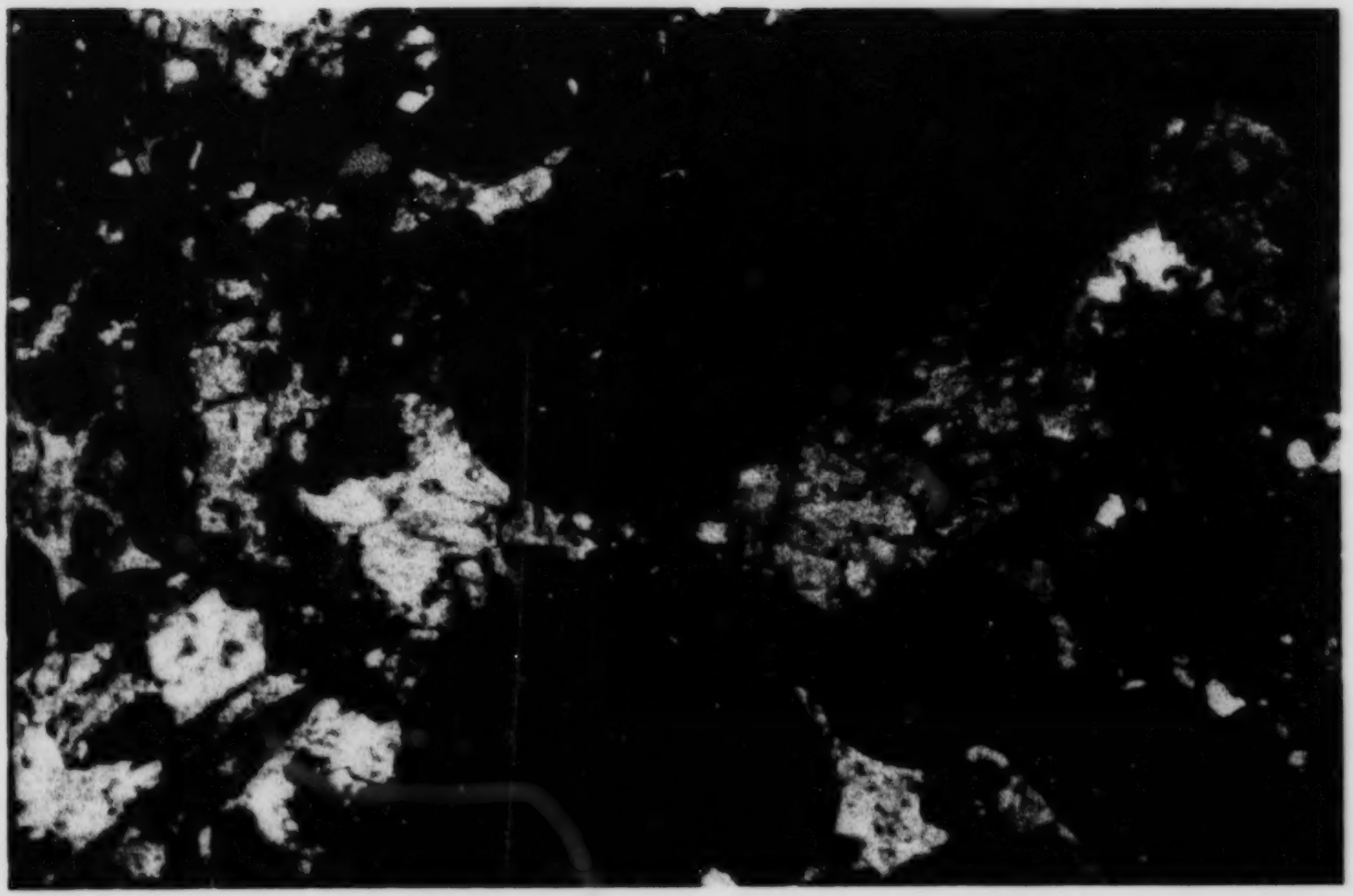
Photomicrograph showing secondary vuggy porosity is not fabric selective and dissolves oolite / oncolite wackestone. Pellets are nucleii for oolites and oncolites. Plane Polarized Light, 10X, Frobisher Formation, 3-13-3-2W2M, 4291'.



Photomicrograph showing partial dissolution of oolites in wackestone containing abraded bivalves, tubular algae and crinoids. Oolites have pelletal nucleii; bryozoa nucleus in centre of image. Plane Polarized light, 10X, Alida Formation, 15-14-8-6W2M, 1202.5m.



Photomicrograph showing intraparticle porosity developed within Ortonella (Blue-Green Dasyclad Algae) tubules. Plane Polarized Light, 10X, Ratcliffe Formation, 1-15-3-19W2M, 6142'.



Photomicrograph showing secondary porosity developed in cemented oolite - tubular algae wackestone. Note abundance of rounded Ortonella (Blue - Green Dasyclad Algae). Plane Polarized Light, 10X, Frobisher Formation, 16-15-8-6W2M, 1199m.

Q

The Upper Devonian Revisited

S. P. (Steve) Halabura
North Rim Exploration Ltd.

THE UPPER DEVONIAN REVISITED

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Saskatoon, Sask.

1.0 Introduction

Since I first looked at the Birdbear Formation in 1980, I have experienced three rejuvenations of the southeast Saskatchewan oil patch. The first rejuvenation occurred with the transfer of mature producing properties from larger integrated oil companies to smaller, entrepreneurial junior explorers and developers who revitalized these properties through the drilling of horizontal wells. The second rejuvenation occurred in the mid-1980s with the discovery of oil in the Middle Devonian Winnipegosis Formation at Tableland. This led to a flurry of deeper drilling, largely focused along a fairway extending from Tableland north to Viewfield. The discovery of Ordovician Red River production at Midale Saskatchewan in 1995 by Berkley Petroleum Corp. is the third rejuvenation and is certainly not the last.

Southeast Saskatchewan has yet to see a major discovery in the Upper Devonian strata which comprise the Duperow and Birdbear Formations, other than minor discoveries in the Birdbear Formation at Walpole, Tatagwa, and Flat Lake *(Slide A)*. The question must be asked as to whether this is due to a lack of reservoir, a lack of oil generation and/or migration, or a lack of trap. The purpose of my talk is to examine the types of Birdbear production discovered to date in Saskatchewan and speculate as to whether it is reasonable to expect a significant discovery to be made in either formation.

The formations of the Saskatchewan Group, i.e. the Birdbear and Duperow Formations, are very significant from an exploration viewpoint for two reasons:

- the average depth to test Saskatchewan Group reservoirs ranges from 1,000m near the Manitoba boundary to 2,400m in the southwestern portion of the region; and
- a significant number of wells drilled since 1980 to test either the deeper Winnipegosis or even deeper Red River provides an excellent opportunity for explorers to hunt for bypassed pay, an extremely important consideration when considering oil targets such as the "Ambrose Zone" of the Duperow Formation.

2.0 Economic Considerations

The only formation of the Saskatchewan Group to have produced oil in Saskatchewan is the Birdbear Formation. Overall, the Birdbear has produced **838,000 m^3** or **5,270,000** barrels of oil from 2 formally designated pools and 7 informal pools *(see Slide B)*. Initial oil in place in southeast Saskatchewan as determined by Saskatchewan Energy and Mines (1995) is **3,228,000 m^3 or 8,900,000** barrels of oil.

Pool	**Discovery Date**	**Depth (m)**	**I.O.I.P. (m^3)**	**Cum. Oil Prod. (m^3)**
Hummingbird	1966	2,326	1,167,000	511,000
Kisbey	1968	1,626	1,452,000	282,000
Tatagwa	1984	1,850	n / a	n / a
Walpole	1984	1,072	n / a	n / a
Misc. (Medium)			492,000	30,000
Misc. (Light)			117,000	15,000
Total:			***3,228,000***	***838,000***

Slide B: Production History, Birdbear Formation

While 8.9 million barrels may not seem like much oil potential, this figure must be considered in the light of total drilling attempts. A recent count of wells capable of production from the Birdbear identified 30 wells from a total of approximately 1,000 Birdbear penetrations, giving a success rate of 3%; however, of the 1,000 wells, more than 800 wells reached total depth in formations deeper than the Birdbear. If the Duperow is included, approximately 500 wells penetrated both formations and reached total depth in the Prairie Evaporite or deeper. When one considers that over 20,000 wells have been drilled in southeast Saskatchewan, only 1 in 20 wells penetrated to the Birdbear and only 1 in 40 tested both formations. One must especially keep in mind that these numbers are weighted in favor of drilling in areas which have produced oil from the Birdbear, therefore they do not represent an even testing of the entire area.

Not only is the Saskatchewan Group poorly tested, but production enhancement through the use of horizontal drilling is in its infancy. For example, two horizontal wells produce from the Birdbear in the Kisbey Pool. The Northrock 2HZ B10-27-A2-27-7-6 produced in 446 days 19,650m3 (123,568 barrels) of oil for an average production rate of 277 barrels of oil per day. The Northrock HZ C2-27-D5-27-7-6 produced in 567 days 21,615m3 (135,960 barrels) of oil for an average production rate of 240 barrels of oil per day. Considering that the Birdbear zone is only 400 meters deeper than the Frobisher - Alida zone, well costs will not have a significant impact upon the economic viability of producing this deeper zone.

3.0 Geological Considerations

Almost every geologist who works southeast Saskatchewan and has looked at the Birdbear Formation is familiar with the Hummingbird Pool. This pool is the result of the multi-stage dissolution of the underlying Prairie Evaporite salt and is located within a region where the Prairie Evaporite has been entirely removed. Unfortunately, the classic Hummingbird model does not explain other Birdbear pools such as Kisbey or Walpole, all of which are "on-salt", i.e. within a region where the Prairie Evaporite salt is present.

The producing zone in the Kisbey Birdbear Pool located in Township 7 Range 6 W2M is from a sequence of dolomitized limestone found within the "intertidal" facies of Halabura (1983). This zone has produced approximately 282,000 m^3 (1,774,000 bo) from 12 wells covering a pool area of approximately 227 hectares (570 acres). Slide C is a stratigraphic cross-section illustrating the general trapping mechanism for the pool. Many geologists believe that the trap at Kisbey is formed by a structural reversal into a local single-stage salt dissolution structure located several miles to the northeast near the Tidewater Kisbey 16-34-7-6 W2M dry and abandoned test well. These geologists are disappointed when they see seismic over the structure and find that the amount of structural reversal is insufficient to account for updip closure; however, examination of wells reveals that updip closure is provided by the thickening of the anhydrites of the upper member of the Birdbear *(Slide C)*.

Close examination of the producing zone at Kisbey suggests that the interval represents a "shoal" zone probably deposited in a high energy, subtidal to intertidal marine environment. This shoal makes a rapid transition to algal laminites, bedded impermeable dolomite, and nodular to bedded anhydrites of a backshoal to locally supratidal environment. This transition from porous and permeable shoal to non-reservoir backshoal rocks forms a regional stratigraphic trap. Examination of wells from other producing areas such as Walpole and Tatagwa shows that this transition may form the primary trapping mechanism.

One often-heard criticism of the Birdbear is that it is "always porous". In support of this statement is reservoir characteristics within shoal bodies of porosity in excess of 25% and average permeabilities exceeding 500 millidarcies. The shoal zone is commonly a bioclastic to intraclastic, chaotically bedded limestone which has been strongly leached, thus creating microvuggy to vuggy fenestral and channel porosity. The matrix rock is often dolomitized, thus creating enhanced intercrystalline porosity. The secondary enhancement of porosity may be due to several factors including:

- Dolomitization of the shoal due to a reflux mechanism;
- Leaching of the carbonate matrix during the early burial of the strata; and
- Further dissolution and leaching of the carbonate matrix during deep burial, possibly the result of the circulation of meteoric waters associated with cross-formational flow induced by proximity of the reservoir to salt dissolution and collapse structures.

An excellent summary of the various lithotypes comprising the Birdbear is provided in Martiniuk et al 1995. It is important to recognize that the Birdbear is essentially composed of three regional lithotypes. The basal unit forming a widespread platform is separated from the equally widespread evaporitic "upper member" by the previously mentioned "shoal" or "intertidal" zone. While one can define the "intertidal" zone throughout southeast Saskatchewan, significant variations in thickness occur. Generally some form of bioclastic to peloidal wackestone to grainstone is present, with local thickenings of bioclastic packstone to grainstone and stromatoporoid - rich "bank" rock. It is within this thickened shoal or intertidal unit that reservoir-grade porosity and permeability is commonly found. The regional platform lithotype may display porosity on well logs; however examination of cores taken in the platform lithotype often shows this unit to be a poorly permeable and ineffective reservoir.

The oil produced from the Birdbear Formation in the Walpole Pool has been linked to a Middle Devonian Winnipegosis source rock (Osadetz, and Brooks, 1992; Martiniuk, et al 1995). Again, this is very significant and is a very important clue with respect to exploring for Birdbear and Duperow oil. If the oil present in the Birdbear has migrated from the underlying Winnipegosis, this means that the normally impermeable intervening strata, including the salts of the Prairie Evaporite, have been made permeable. This can only occur in situations where the Prairie Evaporite has been removed due to dissolution. Subsequent collapse of the overlying strata into the resulting Prairie cavern created the vertical fracture network which would have allowed deeper oil to migrate upward into the highest stratigraphic carbonate sequence, where upward migration was terminated by the shales and evaporites of the Upper Devonian Three Forks Group. While this mechanism seems plausible, there are several considerations which complicate this hypothesis, namely:

- wells penetrating collapse structures often show that removal of Prairie salt is incomplete, with a remnant of salt occurring above the Winnipegosis;
- Salt dissolution almost always predates the time of oil generation and migration, which is currently believed to have occurred during the Eocene between 38 and 32 Ma (Burrus, et al 1995); and
- Examination of cores of true collapse "chimneys" (i.e. the insoluble residue filling a salt dissolution void) shows the residuum to be impermeable.

When one looks at the Duperow, the stratigraphic, sedimentological, and paleogeographic distribution of reservoir and non-reservoir intervals is even more complex than the Birdbear. Most authors agree that the Duperow consists of a series of shallowing-upward depositional cycles; however, the finer points of Duperow geology such as stratigraphic nomenclature, reservoir architecture, and paleogeographic distribution is open to debate. The Duperow is productive in North Dakota and Montana from a variety of pool settings ranging from the classic "Hummingbird-type" multi-stage salt collapse structures to subtle stratigraphic traps such as Ambrose North Dakota (Twp. 163N Rge. 99W). Ambrose is particularly relevant to Saskatchewan explorers of the Upper Devonian not only because of its proximity to Saskatchewan (only several miles south of the U.S. - Canada boundary) but because of its reservoir. The Ambrose Pool has produced 1,177,000 barrels of oil since its discovery in 1983. The producing zone is from an interval I have termed the "Ambrose Zone" which is the lowermost cycle of the Seward Member and the "Flat Lake Zone" of the uppermost Wymark Member ***(Slide D)***. Normally the Flat Lake Zone consists of a halite bed named the "Flat Lake Halite", but this salt may be absent due to dissolution or non-deposition. Both reservoir zones at Ambrose are only a few feet thick and probably not the primary target, since the discovery well for the pool is a deep well completed in the deeper Red River. One wonders how many other "Ambrose-type" pools have been drilled through in southeast Saskatchewan by explorers targeting deeper Winnipegosis or Red River anomalies.

4.0 Conclusions

While great progress has been made in enhancing Mississippian reservoirs through horizontal drilling and in discovering and developing deeper Winnipegosis and Red River oil reserves, not much has happened with respect to the Saskatchewan Group strata. In summary a regional examination of the Saskatchewan Group suggests the following prospect types:

Stratigraphic: This play is based upon the updip termination of the porous shoal facies against the impervious backshoal facies, with lateral trapping provided by the normal wandering of the Birdbear coastline. This type of prospect is considered the riskiest in that current seismic methods may not be refined to the point of identifying porosity variations in the order of 5 to 10 meters.

Strati-structural: As with the purely stratigraphic play type, this play is formed by the regional boundary between the intertidal shoal and backshoal zones, with updip closure provided either by a structural reversal into a salt collapse low or by the presence of a structural nose striking perpendicular to the shoal - backshoal boundary. This play may be less risky than the stratigraphic in that offsetting wells can be used to define the reservoir boundary and seismic can identify the structural component.

Multi-stage structural: This play is the classic "Hummingbird-type" multi-stage collapse structure. While seismic can be used to define the limits of the target and the structural attitude of the reservoir beds, the complexity of salt dissolution and collapse and the resulting cross-formational flow adds risk in terms of oil migration and trap integrity.

Structural: This play is based upon seismically-defined structural closures within the regional shoal trend. This is particularly important if one is exploring for oil associated with deeper Red River basement-related structures.

How does one explore for Saskatchewan Group oil? I believe that the 1,000 existing deep penetrations are a treasure-trove of bypassed pay opportunities as well as starting points for detailed Saskatchewan Group paleogeographic reconstructions, particularly of the Wymark Member of the Duperow and the "shoal" zone of the Birdbear. Given the widespread distribution of favorable reservoir and trapping situations, the potential for significant Saskatchewan Group oil discoveries is great.

The slides used in my talk are posted to our website "www.northrim.sk.ca" and can be downloaded for reference at a reader's convenience.

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Petroleum Hydrogeology of the Upper Yeoman Formation (Red River) in the Williston Basin

*Dan Barson
Kaush Rakhit
Troy Meyers
Carlo Poletto
Shaun Cahoun

Rakhit Petroleum Consulting Ltd

PETROLEUM HYDROGEOLOGY OF THE UPPER ORDOVICIAN YEOMAN FORMATION (RED RIVER) IN THE WILLISTON BASIN

Dan Barson, Kaush Rakhit, Troy Myers, Carlo Poletto and Shaun Cahoun

Rakhit Petroleum Consulting Ltd, 230, 319-2nd. Avenue S.W., Calgary, Alberta, CANADA T2P 0C5

The petroleum hydrogeology of the upper Ordovician Yeoman and Herald Formations (the Red River Formation in the US) was studied as part of a two-year project investigating all oil reservoirs in the Williston Basin. New insights have been gained concerning the total volume of oil expelled into the Red River as well as the patterns of water salinity and water and oil migration patterns. Two major under-developed exploration fairways have been identified. Products for the Red River from our basin-wide project that will be presented in this talk include:

- Source rock maturity map
- Formation water salinity map
- Dynamic Water Migration Map
- Dynamic Oil Migration Map
- Oil/Water Tilt Map showing regions with potential downdip reserves enhancement

Source Rock Maturity and Recoverable Oil Reserves

Red River source rocks occur as thin beds of bituminous lime mudstone called kukersites. The kerogen is composed of *Gloeocapsomorpha prisca* alginite, which occurs in interlaminated and disseminated form. *G. prisca* is a colonial blue-green algae that formed stromatolitic mats in subtidal carbonate ramp settings in the Late Ordovician seaway. Kukersites are preserved over the area where anoxic bottom waters protected the algal mats from predation and bioturbation. Although less than 1 m thick, these source rocks locally attain total organic carbon content exceeding 20% with an average initial petroleum potential of

77 kg HC/tonne source rock (Osadetz and Snowdon, 1995). The richest source horizon is in the upper Yeoman Formation (Red River 'D' zone) with additional kukersite-rich intervals in the underlying Winnipeg Formation and in the overlying Herald Formation (Red River 'B' zone). By creating a geothermal gradient map for the basin we were able to map the temperature distribution on the top of the Red River. Calibrating to rock-eval maturity data from source rock samples from Saskatchewan analysed by the Geological Survey of Canada (Osadetz and Snowdon, 1995), we have identified the 95 °C isotherm in the Williston Basin as the approximate threshold of thermal maturity corresponding to oil expulsion. By overlaying the 95 °C isotherm on the source rock outline mapped by Osadetz (1997 *pers comm*) we have defined the Red River oil kitchen which measures roughly 175 by 400 km (see Figure 1).

Assuming no leakage of oil through the overlying Stoney Mountain shale (Gunn Member in Canada, Stoughton shale in the US), and no loss of oil to outcrop areas, we estimate that ultimate recoverable reserves for the Red River in the Williston Basin are 1.85 billion bbls of oil. This estimate assumes an average source rock thickness of 50 cm, an expulsion efficiency of 25% and a recovery factor of 15% (see Table 1). Cumulative Red River production to January 31, 1997 of 357 million bbls indicates that 1.5 billion bbls of recoverable oil remains in the reservoir. Much of this oil lies undiscovered in sparsely drilled areas.

Water Migration Patterns

In a tilted carrier bed under hydrostatic conditions, oil migrates updip until being trapped on a structural high or against a lateral capillary barrier. In a hydrodynamic system, oil migration is deflected in the direction of water flow and oil can be trapped in unexpected locations offset from structural closures. Tilted oil/water contacts due to water flow are documented at numerous oil fields in the Williston Basin (e.g., Murray 1959, Hubbert 1967, Berg et al 1994, DeMis 1995). Downdip flow has a constructive impact on hydrocarbon accumulation. Downey (1987) documented downdip flow in the Red River driven by recharge on the southwest basin flank in southeast Montana and southwest North Dakota. We confirm this recharge driven flow, which plays a major role in trapping oil in downdip locations in the Red River 'B' Dolomite on the eastern flank of the Cedar Creek anticline in Bowman County.

To properly account for water flow it is necessary to map formation water salinity so that the water density can be determined. In the Red River, water salinity ranges from 40,000 mg/L west of the Cedar Creek anticline to a maximum of 350,000 mg/L in Mountrail County, North Dakota. The high-density brine lens (density exceeding 1.2 g/cc) is displaced northeast of the basin centre. To determine water flow patterns we calculate the force for water flow using hydraulic head distribution but also accounting for the brine density, which acts against the freshwater head gradient on the east and northeast flanks of the basin. Our analysis reveals a previously undetected area of downdip flow extending from Weir Hill, Saskatchewan to Hettinger County, North Dakota, where heavy brine is flowing downdip against the freshwater head gradient and thereby enhancing the local trap potential.

Red River Oil Reserves and Migration Fairways

Using proprietary software that accounts for the influence of water flow and oil buoyancy, we have modelled the Red River oil migration patterns. The oil migration vectors allow us to identify drainage divides within the oil kitchen which are annotated on Figure 1 as *northwest*, *northeast*, *southwest* and *southeast*. The ultimate recoverable reserves calculated in Table 1, have been allocated according to the area of each oil kitchen quadrant and the results are shown in Table 2. By subtracting cumulative production to January 31, 1997, we have estimated the remaining recoverable reserves in each quadrant. Reserves vary from a low of 287 million bbls recoverable for the northwest quadrant to a maximum of 514 million bbls for the northeast quadrant. Oil generated within these quadrants is driven in the direction of the oil force vectors (small arrows on Figure 1) with charge focussing fairways identified by the large arrows. Major shadow zones exist on the east and west flanks of the basin. On the western basin flank, updip oil migration is prevented by focussing along the Cedar Creek anticline and by hydrodynamics. On the east flank, charge is limited by the kukersite edge and by focussing along the Nesson anticline.

The *northwest quadrant* with estimated remaining reserves of 287 million bbls of oil recoverable has charged the Red River structural pools of Mackenzie County in North Dakota and Richland and Sheridan Counties in Montana. The Poplar Dome in Roosevelt County Montana, southwest of the Lone Rider field is potentially charged. In Canada the Minton and Lake Alma Yeoman pools are sourced from this quadrant. Long-distance migration is focussed along a fairway that runs through Daniels County Montana and north into Saskatchewan, west of the Red River oil pool at Mark Bengough 7-10-4-24 W2M. This fairway is very sparsely drilled and has strong potential for future development. The main risk is the long distance migration required (see Figure 1).

The *northeast quadrant* with estimated remaining reserves of 514 million bbls of oil recoverable charged the pools along and adjacent to the Nesson anticline in Williams and Divide Counties, North Dakota. Long distance migration is focussed along two fairways in Saskatchewan, accounting for the Midale and Weir Hill Yeoman pools as well as the oil fields recently discovered at Mansur, Creelman and Kingsford. The strongest charge focussing occurs along the Nesson anticline in North Dakota and along a narrow fairway that runs midway between Midale and Weir Hill in Saskatchewan. Southwest Manitoba lies at the edge of the shadow zone, so Red River charge potential there appears poor. The southwest Manitoba region may have been charged if an early phase of Red River oil migration occurred prior to the main structuring of the Nesson anticline which took place in Paleocene (?) time during the Laramide orogeny (Gerhard et al , 1987).

The *southwest quadrant* of the mature source region with estimated reserves of 329 million bbls of oil remaining recoverable, drains into the Cedar Creek anticline and also feeds the 'B' Dolomite play of Bowman County. This is the region where most of the Red River production to date (266 million bbls or 74% of the total cumulative Red River production for the basin) has been achieved. Due to strong downdip water flow in Bowman County we anticipate oil water contacts tilted to the northeast in many of the 'B' Dolomite pools such as Horse Creek, Medicine Pole Hills and Cold Turkey Creek. Longer distance migration is focussed directly towards the Buffalo and Bull Creek fields in South Dakota beyond our map area.

In the *southeast oil kitchen quadrant* with estimated reserves of 362 million bbls of oil remaining recoverable versus cumulative Red River production of only 20 million bbls, strong charge focussing occurs south of the Billings anticline. Here converging water flow creates a narrow oil migration fairway running through Slope and Adams Counties in southern North Dakota. The eastern part of this source rock quadrant drains updip to the southeast with no particular flow focussing apparent although the band of density driven downdip water flow in Grant and Morton Counties creates local hydrodynamic trap potential. Like the northeast quadrant, this fairway is very sparsely drilled and has strong potential for future development.

Acknowledgements: Thanks to Kirk Osadetz (Geological Survey of Canada) and Peter Aukes (Capra Energy Limited) for interesting discussion and input to the Williston Basin Hydrogeology project from which this work is taken. Thanks also to Mary Bluemle (Minerals Diversified Services Inc.) for providing up-to-date Williston Basin oil production data.

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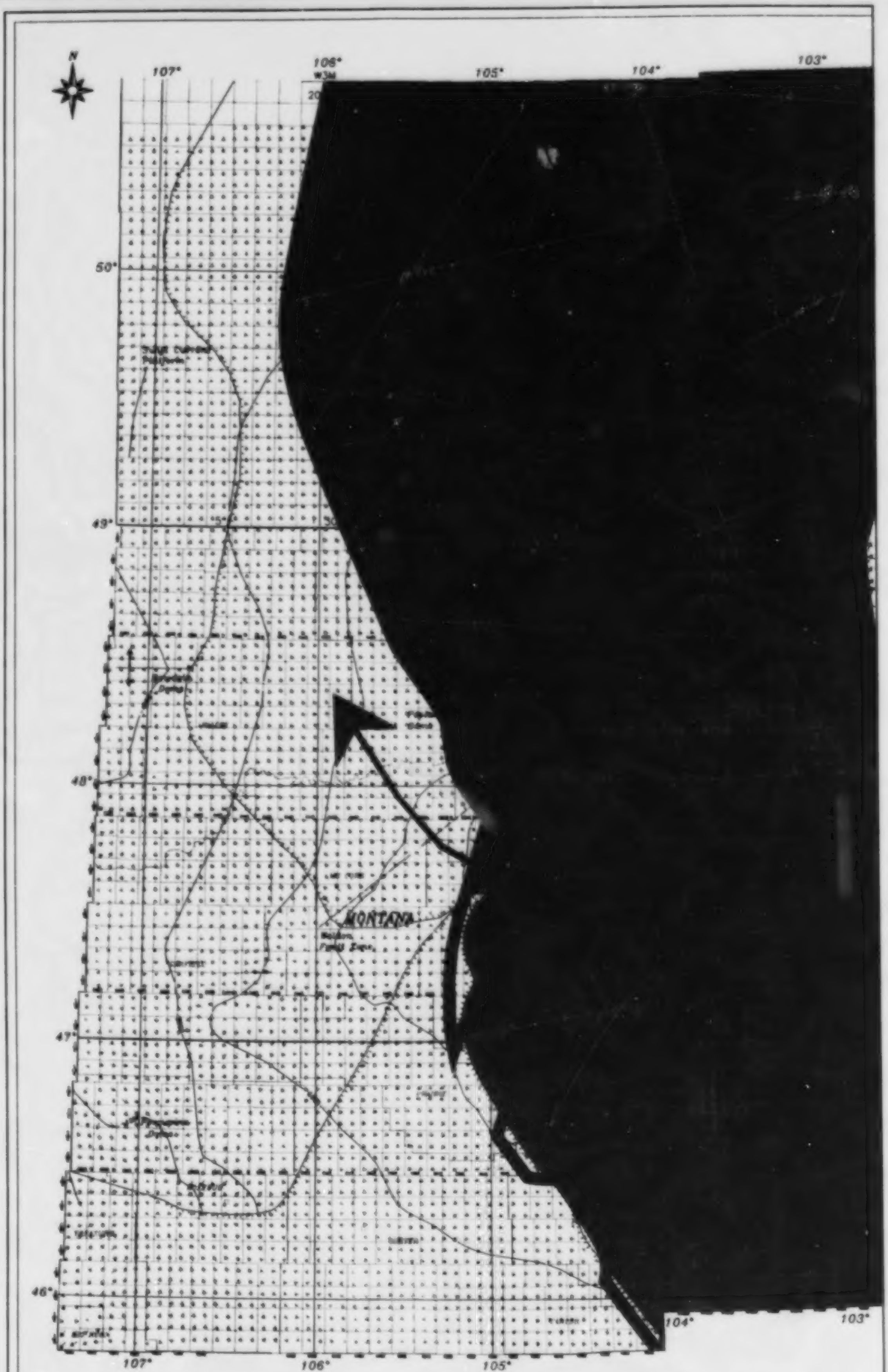
N
107°
106°
W3M
20
105°
104°
103°
50°
30
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MONTANA
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107°
106°
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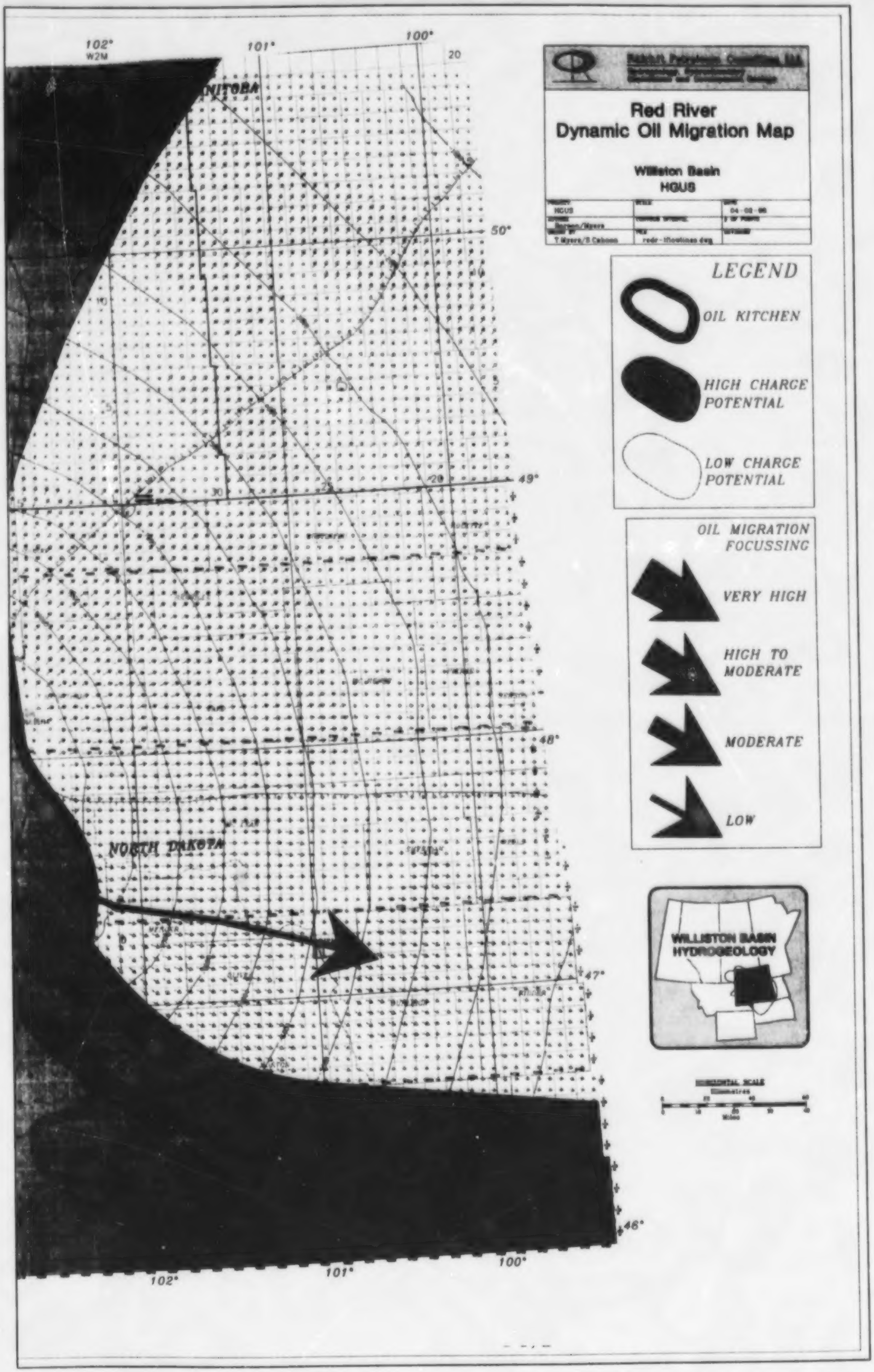


Red River
Dynamic Oil Migration Map

Williston Basin
HGUS

HGUS
04-02-96
T Myers/S Cabono
LEGEND
OIL KITCHEN
HIGH CHARGE POTENTIAL
LOW CHARGE POTENTIAL
OIL MIGRATION FOCUSSING
VERY HIGH
HIGH TO MODERATE
MODERATE
LOW
WILLISTON BASIN HYDROGEOLOGY
MANITOBA
NORTH DAKOTA
102°
W2M
101°
100°
50°
49°
48°
47°
46°
20
30

Table 1 Oil Expulsion Estimate for Upper Ordovician Yeoman-Herald (Red River) Source Rock in Williston Basin

	MATURE SOURCE ROCK						OIL GENERATED		OIL EXPELLED			
Zone	thickness[a]	area[b]	volume	density[c]	mass	IPP[a]	mass	volume	expulsion efficiency	volume expelled	recovery factor	ultimate recoverable
	m	*m^2*	*m^3*	*tonne/m^3*	*tonnes*	*kg/tonne*	*kg*	*bbls*	%	*billion bbls*	%	*billion bbls*
Yeoman-Herald (Red River) Formations	0.5	6.90E+10	3.45E+10	2.5	8.62E+10	77	6.67E+12	4.93E+10	25%	12.3	15%	1.85

a *Osadetz & Snowdon, 1995: Significant Paleozoic Petroleum Source Rocks in the Canadian Williston Basin.*

b *Rakhit Petroleum Consulting Ltd., 1998: Hydrogeology of the Williston Basin*

c *Dresser Atlas, 1982: Well Logging and Interpretation Techniques, p. 89 (Gulf Coast Shale at 9,000 ft.)*

parameters:

oil kitchen area	*175 x 400 km*
source rock thickness	*50 cm*
oil gravity	*35 API (850 kg/m3)*
expulsion efficiency	*25%*

Table 2 Oil Reserves by Source Rock Quadrant, Upper Ordovician Yeoman-Herald (Red River) , Williston Basin

Oil Kitchen Quadrant and Migration Fairway	Cumulative Oil Production to Jan 31, 1997 *million bbls*	%	'Estimated Ultimate Recoverable Reserves *million bbls*	%	Remaining Recoverable Reserves *million bbls*	%
NW (northeast Montana, Sask west of Regina)	61	*17%*	348	*19%*	287	*19%*
NE (northwest North Dakota, Sask east of Regina)	11	*3%*	525	*28%*	514	*34%*
SW (Cedar Creek Anticline)	266	*74%*	595	*32%*	329	*22%*
SE (southern North Dakota)	20	*6%*	382	*21%*	362	*24%*
Total Red River in Williston Basin	358	*100%*	1,851	*100%*	1,492	*100%*

Note:
Quadrant locations are shown in Figure 1
Total Reserves estimate is from Table 1
Reserves are assigned in proportion to the Oil Kitchen quadrant areas (oil generation and expulsion are assumed to be uniform across oil kitchen)
All oil is assumed to remain within the Red River (no vertical leakage, no loss to outcrop)

S

Horizontal Drilling Activity in the Ordovician Red River Formation of the Williston Basin: The Importance of Analogs

Larry Kovac
Canadian Discovery

Horizontal Drilling Activity in the Ordovican Red River Formation of the Williston Basin The Importance of Analogs

by Larry Kovac

Introduction

The main purpose of this talk is to provide a current overview of horizontal drilling activity in the Red River Formation of the Williston Basin. Exploration and development drilling for this play has rapidly expanded during the last few years in both the United States and Canada. Reasons for the increase can be attributed to many aspects that include topics such as government incentive plans, deep land rights reversion, freehold distribution, advances in seismic and drilling technology as well as rig availability. Each of these can provide an incentive to drill depending on the location of the play.

A common benefit to industry has been the over ten years of "learning curve experience" in the field of horizontal drilling. During this time a variety of horizontal applications have been tested on numerous reservoir types throughout North America and the rest of the world. The overall goal of improved recovery factor remains constant but variations in reservoir character and hydrocarbon product have prompted us to come up with new and innovative techniques when applying horizontal drilling.

A major effect of this for the Red River formation is that horizontal drilling programs are being applied to numerous pools under various stages of reservoir development. These range from highly developed fields, to partially developed reservoirs, to newly discovered exploration pools. Each scenario appears to have a varying scale with which to measure success. In one aspect, this would be expected since numerous companies ranging from small to large players drill horizontal wells under their own unique set of economic conditions.

In order to track the progress of over 10,000 horizontal wells now completed throughout the Western Canada Sedimentary Basin, Canadian Discovery uses an array of available geologic and engineering parameters that helps to characterize any reservoir. On a detailed scale, each reservoir is unique, but on a broad scale this approach can provide a realistic framework in which to make comparisons from one horizontal drilling project to the next. Reviewing the activity of similar reservoir analogs over time enables us to measure advances made in horizontal drilling technology. It also allows us to rank which projects are most successful and make some broad predictions as where to look for new horizontal drilling programs.

An important step in this approach is to first establish why the horizontal application is being made. Asking the question of "why drill a horizontal well" becomes the main focus for all disciplines involved in a project. Answering the question in light of the reservoir's character and cross referencing it to any similar analogs will help to assess the degree of risk before the bit turns.

Using this approach, a review of the Red River formation is made in which the gross features that characterize a potential reservoir are highlighted. They include brief comments on an array of parameters such as depositional environment, variation in lithotypes, possible structural influences and the importance of understanding its diagenetic history.

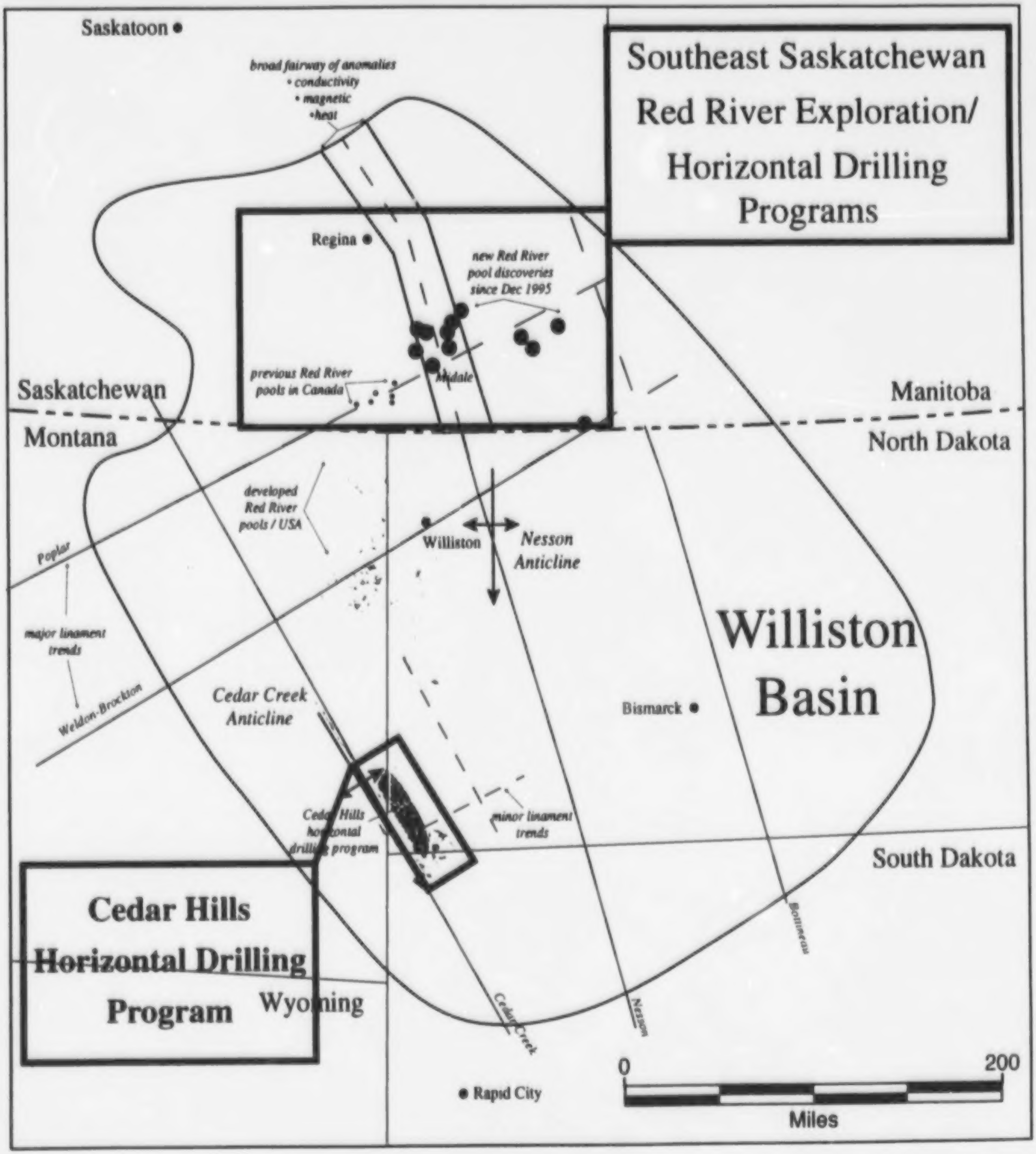
A closer look is made by examining the general aspects of pay and non-pay thickness, porosity and permeability, as well as the scale and degree of heterogeneity. The main application for drilling a horizontal well in the Red River formation and its potential target zone(s) will also be proposed.

Support for this can be found in other Mississippian and Devonian carbonate reservoirs that were exploited horizontally in a similar manner over the past years.

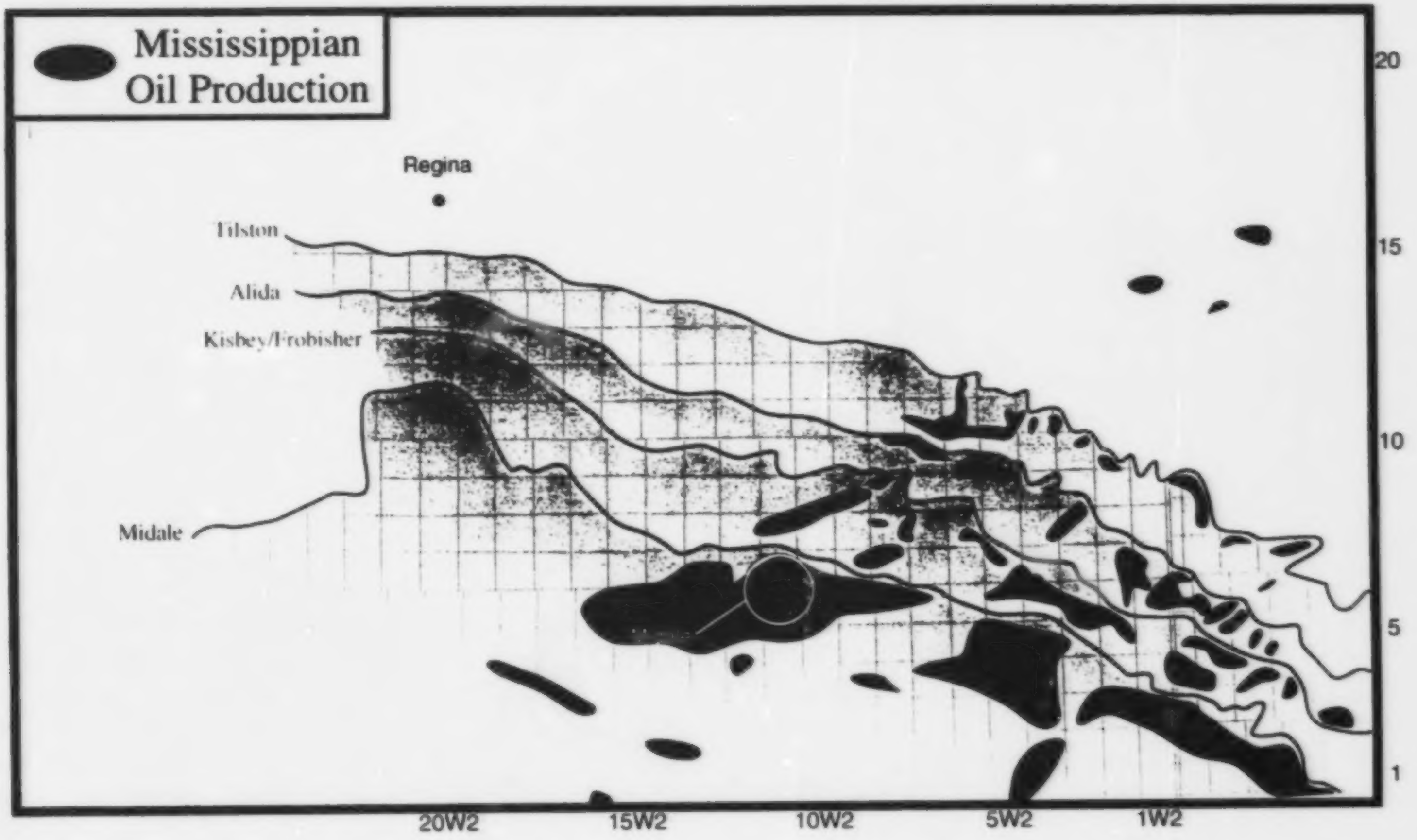
The latter part of the presentation will focus on horizontal drilling and production results for some of the ongoing projects in the Williston Basin. It will include observations on the Cedar Hills horizontal project in South Dakota and a summary of cumulative production to date. Other projects reviewed will include activity in Southeastern Saskatchewan. Comparisons will be made in the exploitation of new and old pool areas such as Midale and Minton which have been tested by horizontal drilling soon after a stratigraphic test and on re-entry candidates.

The slide presentation and discussion for this talk will cover the following topics:
1. Why industry employs horizontal drilling programs and how we can track progress.
2 .Characterization of the Red River Formation on the macro and micro scale.
3. The primary horizontal drilling application for the Red River play.
4. Variations in play development on a regional scale.
5. Project results in the USA - Cedar Hills Horizontal Project
6. Project results in Canada - Southeast Saskatchewan, Midale and surrounding area
7. Future Trends in the Red River Formation

Please Note: An expanded version of this presentation, including the main points for each topic, will be available as a separate handout on the day of the talk. This will be complimented with additional and updated illustrations.

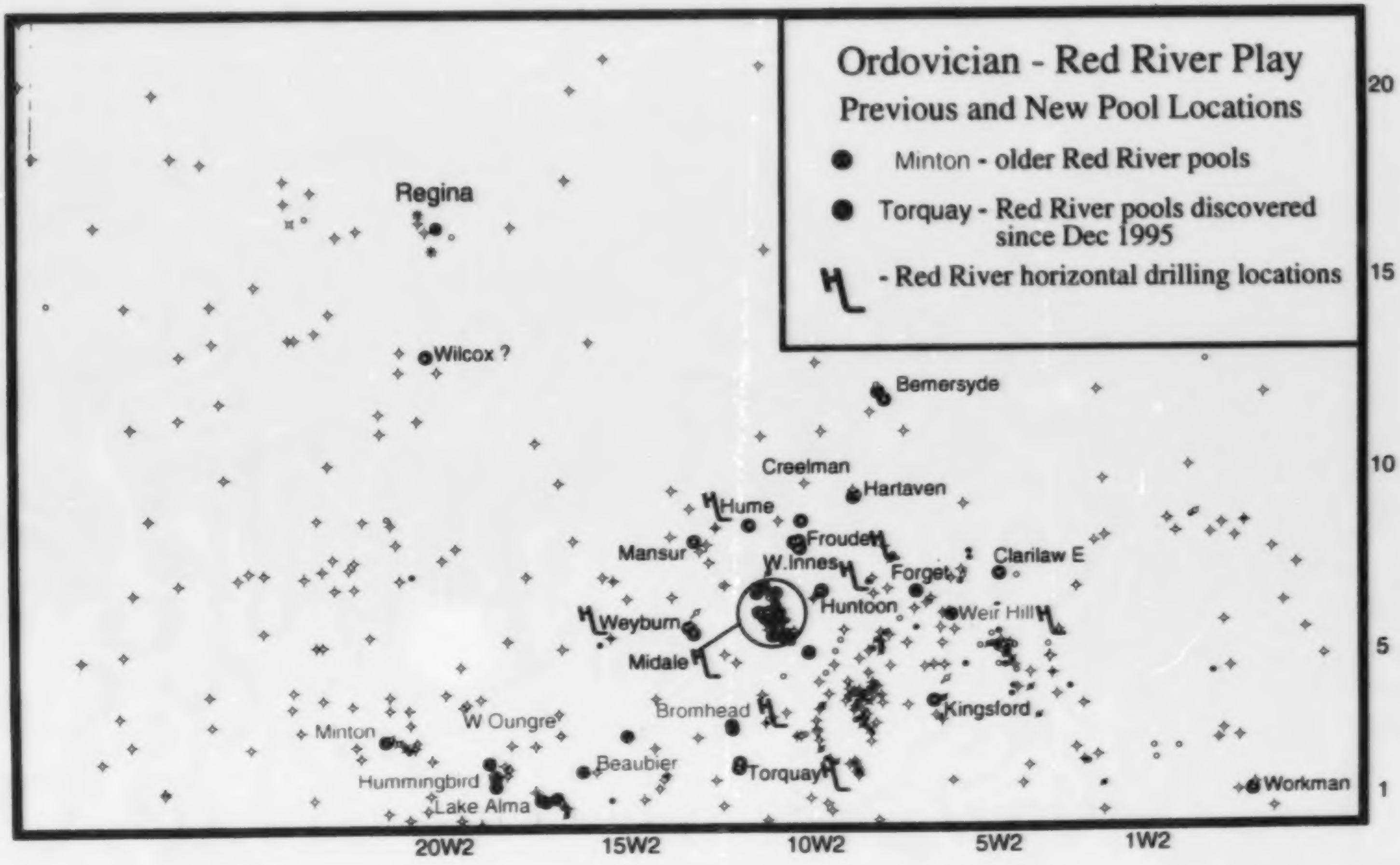

Southeast Saskatchewan Red River Exploration/ Horizontal Drilling Programs
Saskatoon
broad fairway of anomalies
• conductivity
• magnetic
•heat
Regina
new Red River pool discoveries since Dec 1995
previous Red River pools in Canada
Midale
Saskatchewan
Manitoba
Montana
North Dakota
developed Red River pools / USA
Williston
Nesson Anticline
Poplar
major linament trends
Weldon-Brockton
Williston Basin
Cedar Creek Anticline
Bismarck
Cedar Hills horizontal drilling program
minor linament trends
South Dakota
Bottineau
Cedar Hills Horizontal Drilling Program
Wyoming
Cedar Creek
Nesson
0
200
Miles
Rapid City

Southeast Saskatchewan

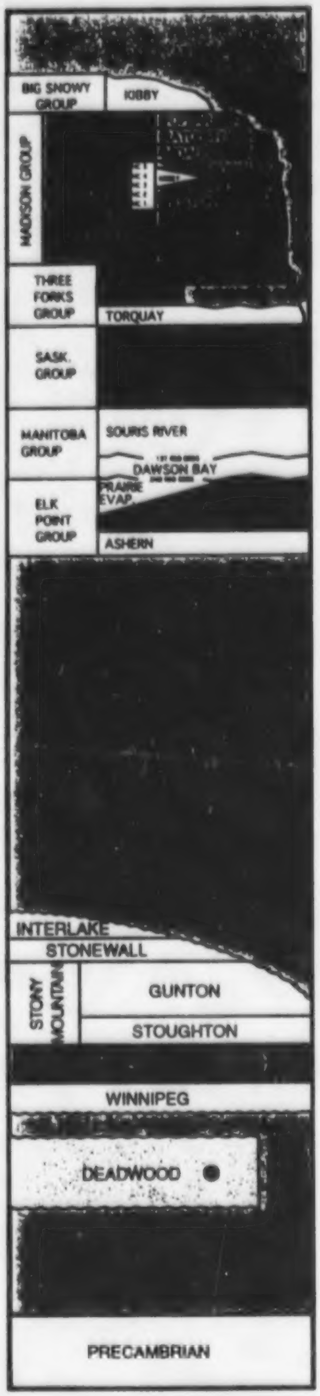

● Mississippian Oil Production
Regina
Tilston
Alida
Kisbey/Frobisher
Midale
20
15
10
5
1
20W2
15W2
10W2
5W2
1W2

Mississippian Subcrop Map

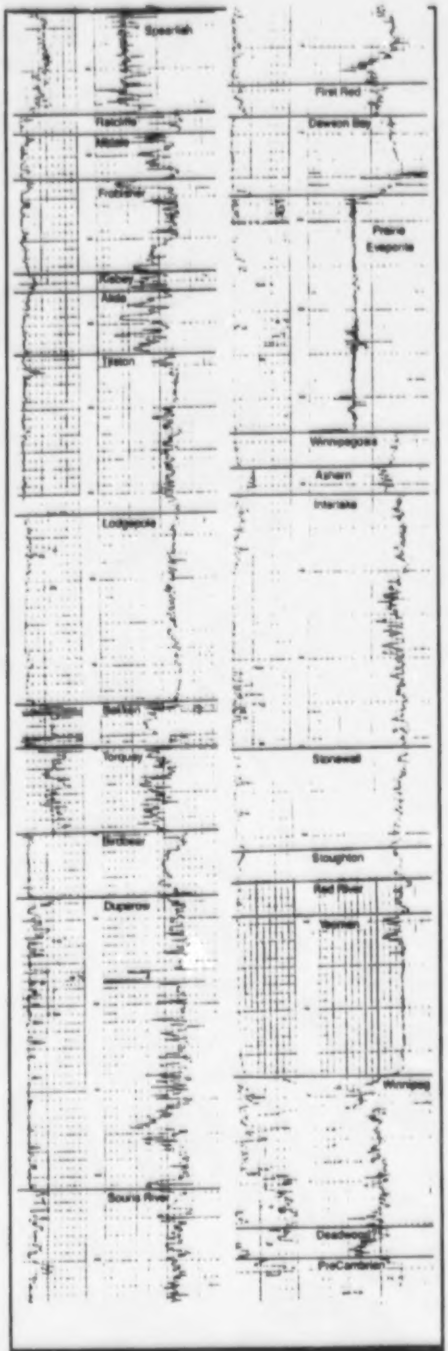
Southeast Saskatchewan


Ordovician - Red River Play
Previous and New Pool Locations
● Minton - older Red River pools
● Torquay - Red River pools discovered since Dec 1995
- Red River horizontal drilling locations
Regina
Wilcox ?
Bemersyde
Creelman
Hartaven
Hume
Froude
Mansur
W.Innes
Forget
Clarilaw E
Huntoon
Weir Hill
Weyburn
Midale
Kingsford
Bromhead
W Oungre
Minton
Hummingbird
Lake Alma
Beaubier
Torquay
Workman
20W2
15W2
10W2
5W2
1W2
20
15
10
5
1

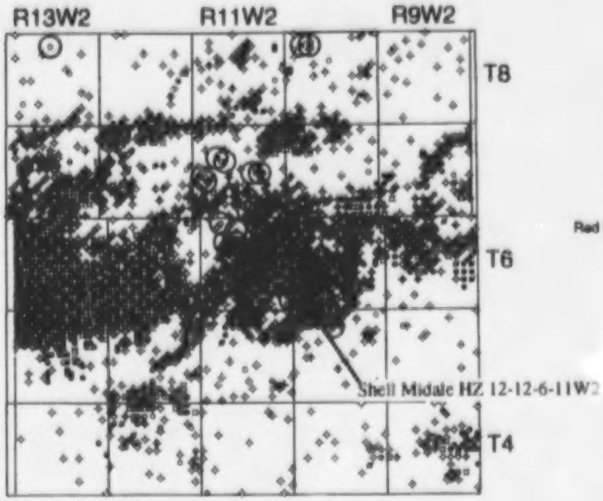
Ordovician Pools Map


BIG SNOWY GROUP
KIBBY
MADISON GROUP
THREE FORKS GROUP
TORQUAY
SASK. GROUP
MANITOBA GROUP
SOURIS RIVER
DAWSON BAY
ELK POINT GROUP
PRAIRIE EVAP.
ASHERN
INTERLAKE
STONEWALL
STONY MOUNTAIN
GUNTON
STOUGHTON
WINNIPEG
DEADWOOD
PRECAMBRIAN

Primary Target ●
Secondary Target •

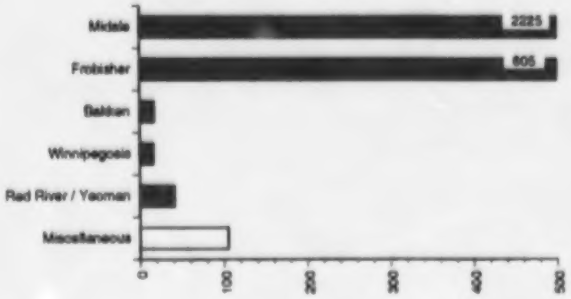


GR/SONIC Berkley et al Midale 10-29-6-11W2
Pumping Red River Oil
IP = 294 bopd PP = 40 bopd
Cum = 40,780 bbls oil


R13W2
R11W2
R9W2
T8
T6
T4
Shell Midale HZ 12-12-6-11W2

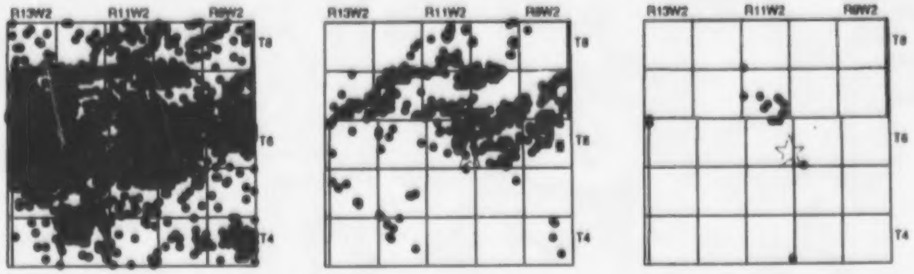
Regional Setting of the Midale Prospect Area

(Red River / Yeoman wells highlighted)



Number Of Wells Deemed Capable of Production by Stratigraphic Interval

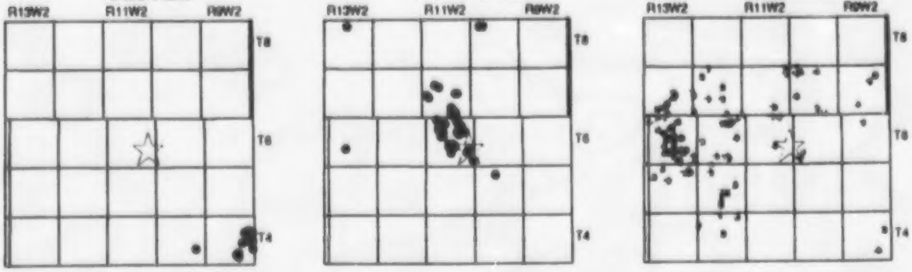
Midale Prospect Area


R13W2
R11W2
R9W2
T8
T6
T4

MIDALE

FROBISHER

BAKKEN


R13W2
R11W2
R9W2
T8
T6
T4

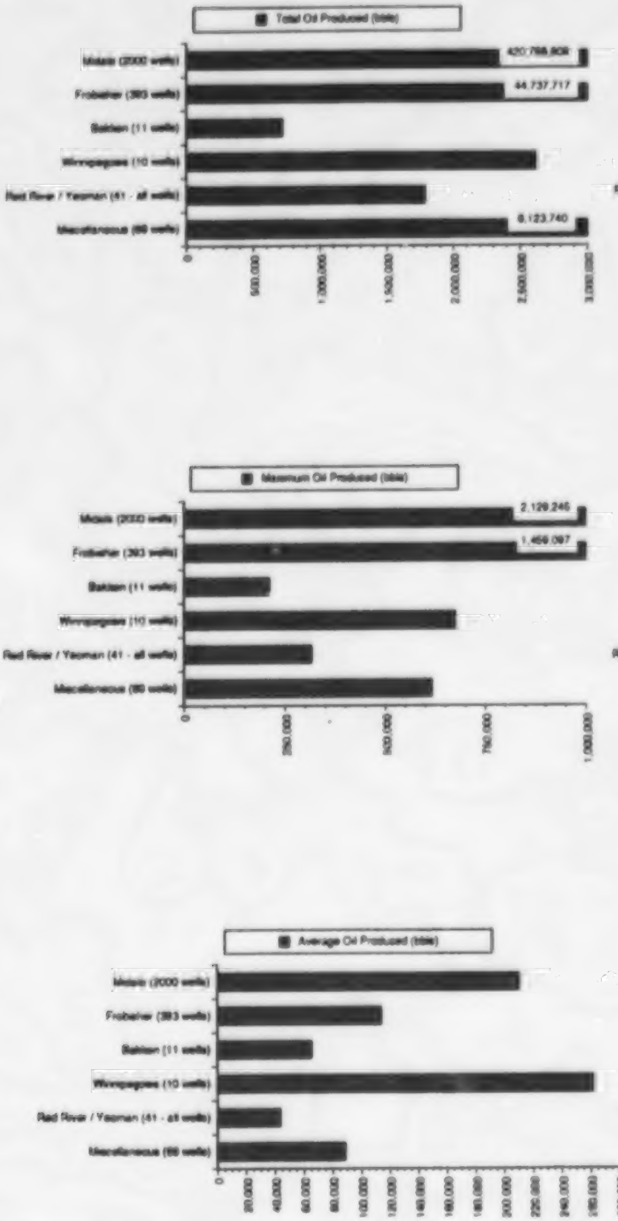
WINNIPEGOSIS

RED RIVER / YEOMAN

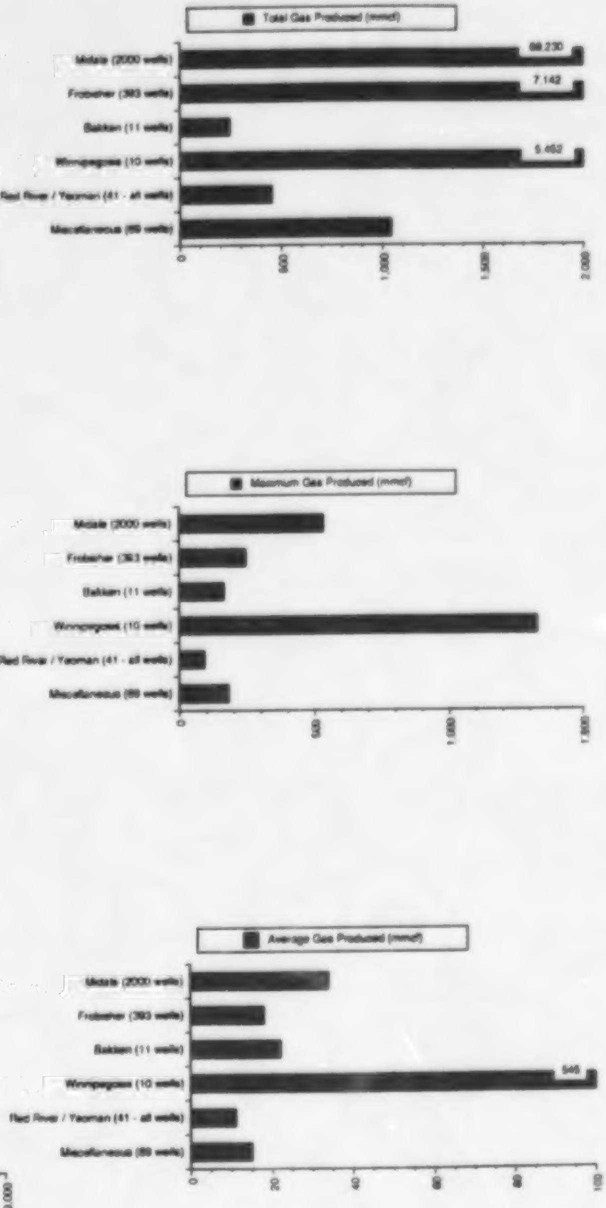
MISC. / UNDEFINED

Areal Distribution of Production by Stratigraphic Interval

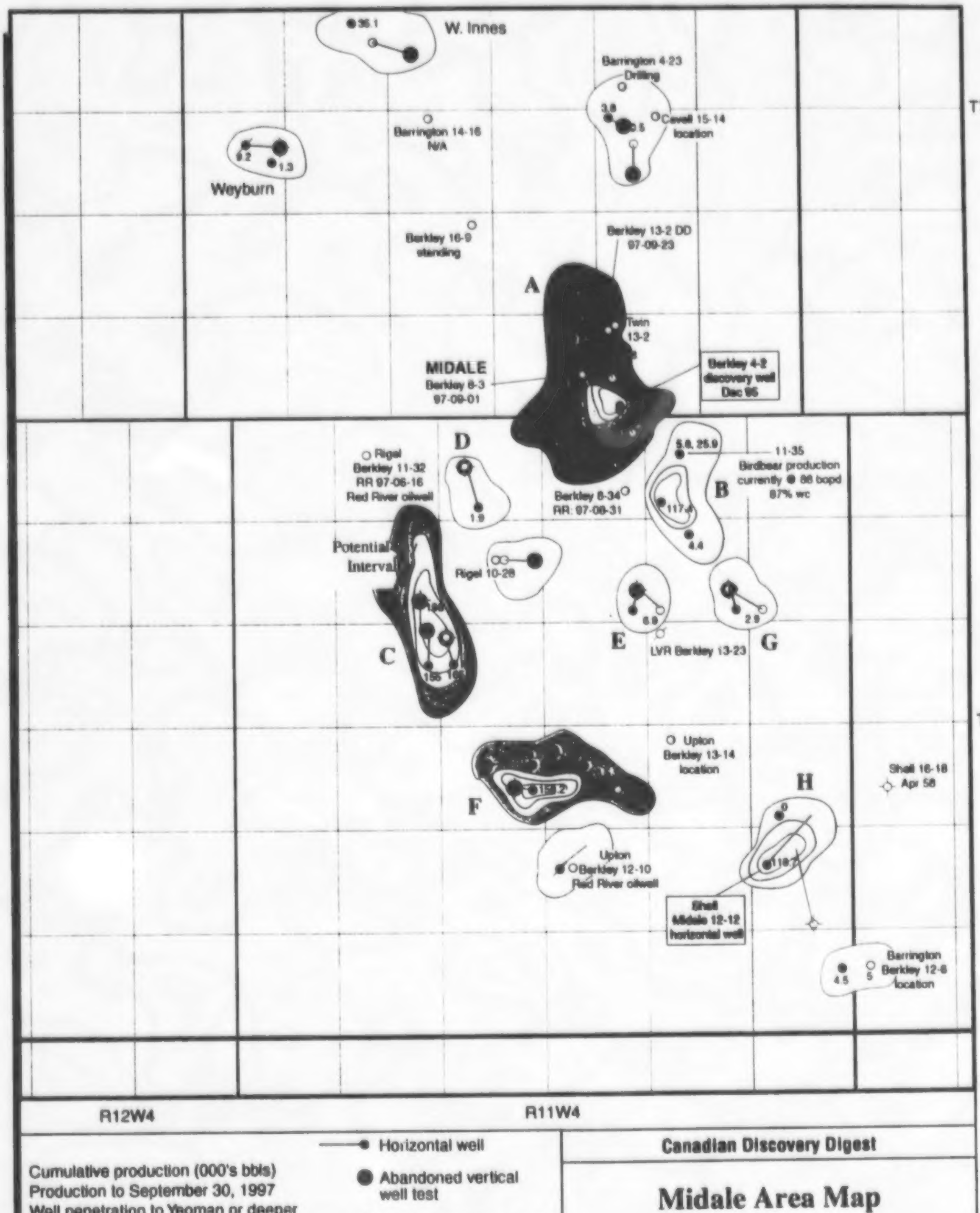
Midale Prospect Area



Oil Production by Stratigraphic Interval
Midale Prospect Area

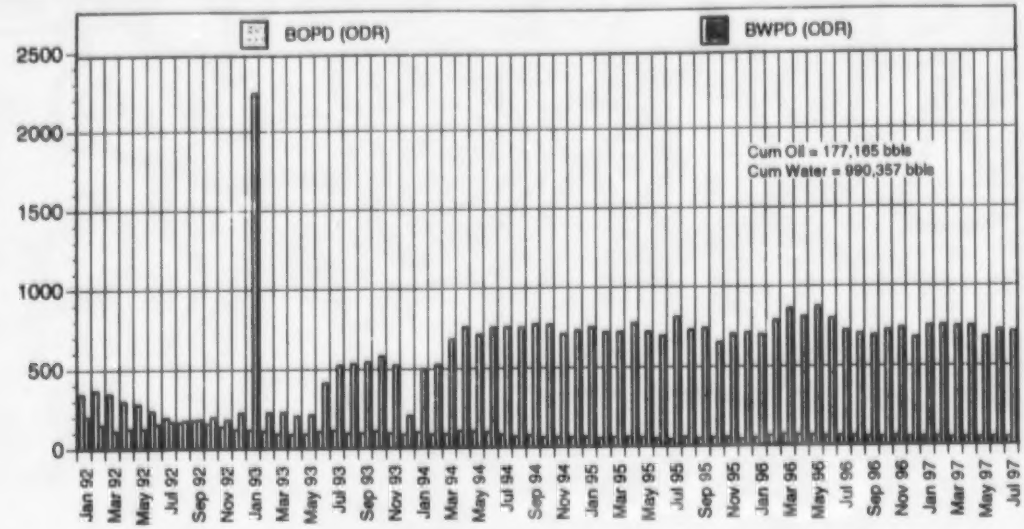


Gas Production by Stratigraphic Interval
Midale Prospect Area

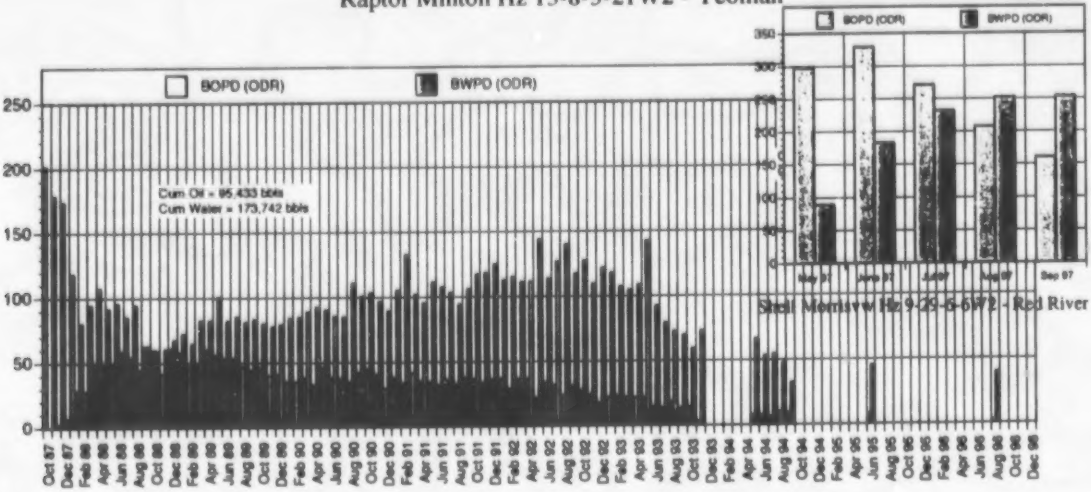

35.1
W. Innes
Barrington 4-23
Drilling
3.8
3.5
Cavell 15-14
location
Barrington 14-16
N/A
9.2
1.3
Weyburn
T7
Berkley 16-9
standing
Berkley 13-2 DD
97-09-23
A
Twin
13-2
MIDALE
Berkley 8-3
97-09-01
Berkley 4-2
discovery well
Dec 95
D
5.8, 25.9
11-35
Birdbear production
currently @ 86 bopd
87% wc
Rigel
Berkley 11-32
RR 97-06-16
Red River oilwell
1.9
Berkley 8-34
RR: 97-08-31
117.4
B
4.4
Potential
Interval
Rigel 10-28
6.9
2.9
E
LVR Berkley 13-23
G
C
155
T6
Upton
Berkley 13-14
location
F
H
Shell 16-18
Apr 58
0
Upton
Berkley 12-10
Red River oilwell
118.7
Shell
Midale 12-12
horizontal well
Barrington
Berkley 12-6
location
4.5
5
T5
R12W4
R11W4
Horizontal well
Cumulative production (000's bbls)
Production to September 30, 1997
Well penetration to Yeoman or deeper
Abandoned vertical well test
A Berkley Pool Designation
Map base generated with AccuMap / IPL well data / PI/Dwights land data

Canadian Discovery Digest

Midale Area Map
Red River Activity

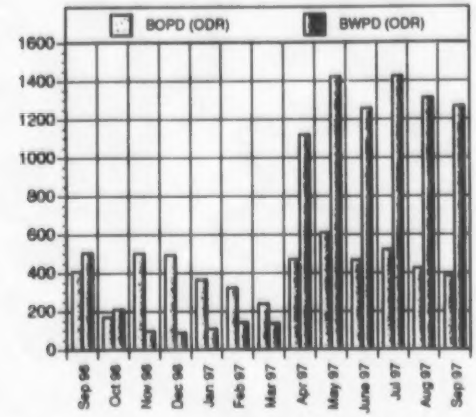


Raptor Minton Hz 13-8-3-21W2 - Yeoman

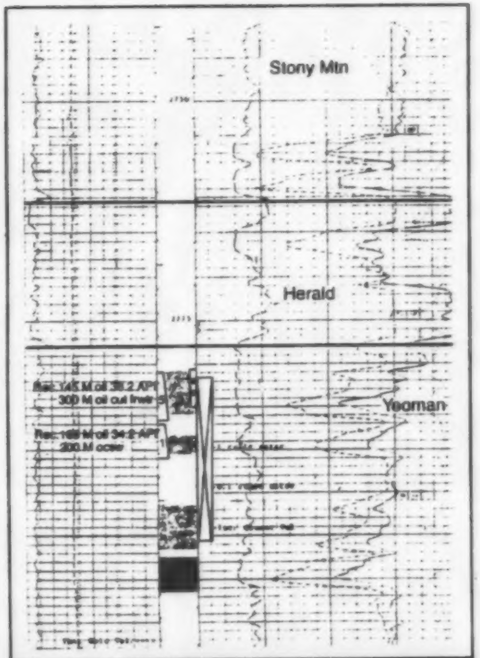


Shell Morrisview Hz 9-29-6-6W2 - Red River

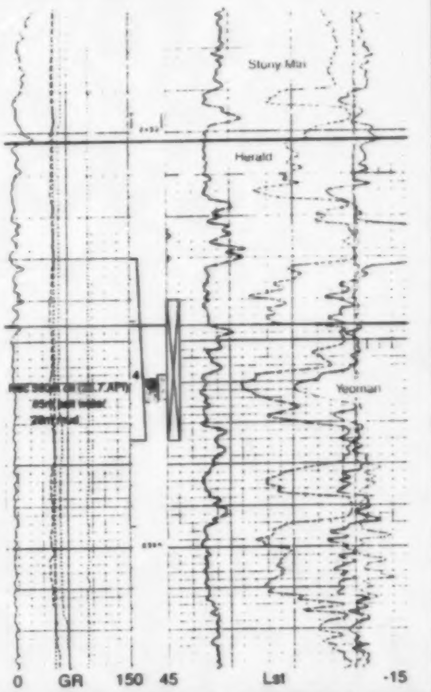
Aldon Weir Hill 9-29-6-6W2 - Red River



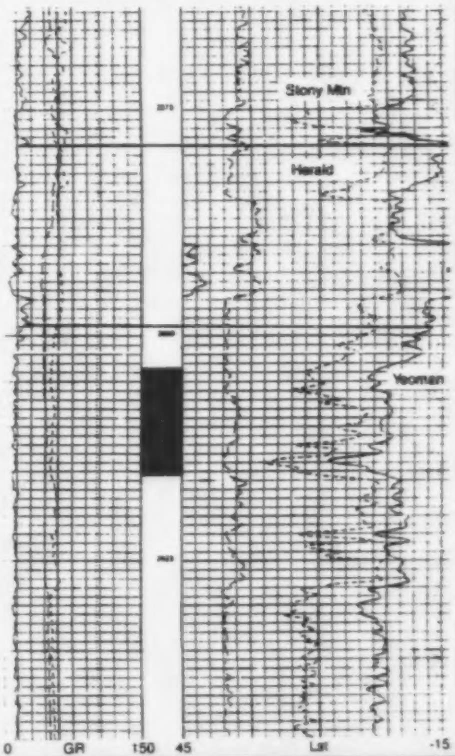
Shell Midale Hz 12-12-6-11W2 - Red River



GR/CNFD Raptor Minton 1-18-3-21W2
Pumping Yeoman Oil
IP = 195 bcpd PP = 19 bcpd
Cum =147,247 bbls oil



GR/CNFD Aldon Weir Hill 9-29-6-6W2
Suspended Red River Oil
IP = 201 bcpd
Cum = 95,433 bbls oil



GR/CNFD Lateral Vector Berkley Midale 13-23-6-11W2
Dry and Abandoned

PRODUCTIVITY COMPARISON BETWEEN OLD AND NEW RED RIVER POOLS					
Field / Pool	**Operator Discovery Well**	**Discovery Date**	**Initial Production Rate (bopd)**	**Total # of producing Wells(#HZ)**	**Cum. Oil per pool (bbls)**
Lake Alma	CDR 1-14-1-17W2	June, 1963	186	3	827,000
Beaubier	Mobil 7-20-2-16W2	Jan., 1967	66	1	5,900
Hummingbird	Imperial 5-13-2-19W2	Nov., 1957	69	1	3,900
Bromhead	Esso 6-28-3-12W2	June, 1980	34	2 (1)	88,900
West Dunbre	Tarragon 4-22-3-15W2	July, 1985	71	1	9,300
Minton	Mark 11-2-3-1W2	June, 1976	88	7 (1)	1,032,000
Weir Hill	Gulf (now Aldon) 9-29-6-6W2	Sept., 1987	200	2 (1)	122,600
Midale A	Berkley et al 4-2-7-11W2	Dec., 1995	1,611	6 (2)	600,000
Midale B	Berkley et al 4-35-6-11W2	March, 1996	158	3	132,000
Midale C	Berkley et al 4-29-6-11W2 HZ	Sept., 1996	530	8 (3)	597,500
Midale D	Berkley et al 3-33-6-11W2 HZ	Dec., 1996	33	1 (1)	4,100
Midale E	Shell et al 1-27-6-11W2 HZ	Jan., 1997	150	2 (1)	10,100
Midale F	Upton/Berkley 11-16-6-11W2 HZ	Oct., 1996	113	4 (3)	353,000
Midale G	Shell et al 1-26-6-11W2 HZ	Jan., 1997	84	2 (1)	3,100
Midale H	Shell 12-12-6-11W2 HZ	Sept., 1997	365	2 (1)	131,700

RECENT RED RIVER OIL POOL DISCOVERIES

Field / Pool	Operator	Discovery Well	Rig Release	Comments
Workman	**Interaction/ Renata**	**3-27-1-32W1**	**97-11-12**	**Confirmed Red River oil well. Second location planned for 3-34.**
Torquay	Cavell/ Grad& Walker	9-21-2-12W2	97-09-18	Vertical well converted to a horizontal. in order to improve recovery.
Kingsford	**Northrock/ Richland**	**8-14-4-7W2**	**97-09-23**	**Dual zone producer; Winnipegosis and Red River capable of 400 and 1000 bopd respectively. Second well drilled to produce the Winnipegosis.**
Weyburn	PanCanadian	4-16-6-13W2	97-09-14	Well cased as a Red River oil well.
Clarilaw East	**Berkley/Richland/ Pan Canadian**	**4-35-7-5W2**	**97-06-26**	**Red River oil well. Tested clean oil at 150 bopd; stable production 85 bopd.**
Forget	Tarragon	11-16-7-7W2	97-06-27	Confirmed Red River oil well. Poor oil production, high water cuts.
Huntoon	**Oiltec/Empire**	**14-13-7-10W2**	**NA**	**Confirmed Red River oil well. Flowing light gravity (39.4 API) crude. No water.**
West Innes	Tarragon	15-20-7-11W2	97-01-09	Confirmed Red River oil well. Anomaly tested with a follow up horizontal well.
Weyburn	**Berkley**	**8-18-7-11W2**	**97-03-30**	**Cased Red River oil well. Cavell added a horizontal well to the pool.**
Froude	Berkley	2-32-8-10W2	97-01-08	Red River oil well with production test rates up to 1875 bopd. A second pay zone in the Winnipegosis to be tested by a horizontal well.
Mansur	**Oiltec/Empire**	**1-33-8-13W2**	**97-10-28**	**Confirmed Red River oil well flowing light gravity, water free crude at controlled rates.**
Creelman	Rigel/Barrington	5-15-9-10W2	97-11-26	Confirmed Red River oil well.
Hume	**Barrington/ Northrock**	**10-12-9-12W2**	**97-10-11**	**Vertical well cased for Red River oil. Converted to a horizontal well.**
Hartaven	Founders/ Berkley	7-2-10-9W2	97-07-25	Confirmed two pay zones in the Red River. Top zone tests 592 m of 46 API oil. Lower zone estimated to be 13 m thick. Two follow up wells have initial rates of 300 and 600 bopd.
Bemersyde	**Startech**	**5-34-12-8W2**	**97-07-04**	**Cased well tested Red River oil, multi-zone potential. Currently shut in. Other vertical wells to test separate anomalies.**
Wilcox	Canadian Coastal (Northrock)	6-33-13-20W2	97-10-18	Rumored Deadwood oil test. Rumored cased and producing Red River oil.

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Controls on Deadwood and Winnipeg (Cambrian and Ordovician) Oil Production at Newporte Field, Renville County, North Dakota

*Michael L. Hendricks
Hendricks and Associates, Inc.

Jacob D. Eisel
Eisel Oil

David W. Fischer
Fischer Oil and Gas

CONTROLS ON DEADWOOD AND WINNIPEG (CAMBRIAN AND ORDOVICIAN) OIL PRODUCTION AT NEWPORTE FIELD, RENVILLE COUNTY, NORTH DAKOTA

by

Michael L. Hendricks (Hendricks and Associates, Inc, Denver, Colorado), Jacob D. Eisel (Eisel Oil, Boulder, Colorado), and David W. Fischer (Fischer Oil and Gas, Grand Forks, North Dakota)

Oil and gas were first discovered at Newporte field in 1977 with the completion of the Shell Oil # 23-X-9 Larson. This well tested significant amounts of oil on a DST of the lower Deadwood sandstones. The well was completed, but because of acid-sensitivity problems during completion, this well never had substantial oil production. Six additional wells were drilled by Shell Oil in the field and three were completed (two of the completed wells were in thin Winnipeg sandstones). All completed wells had minimal oil production.

The Deadwood sandstones are fine to very coarse-grained quartz sandstones. Locally, the sandstones are cross-stratified , glauconitic, chloritic, and garnetiferous. Winnipeg sandstones are fine to very coarse-grained, cross-stratified, and burrow-mottled. Quartz overgrowths are locally common, significantly reducing overall permeability. Basin-wide, authigenic clays play important roles in reservoir quality, and are susceptible to pH reactions produced by drilling and completion fluids. It is inferred that acid susceptibility, produced by reactions of hydrochloric acid with chloritic clays during perforations, significantly reduced the productive capacity of the wells completed by Shell.

In May of 1996, Eagle Operating reentered the # 23-X-9 Larson and perforated the three lower Deadwood sandstone benches. No stimulation was used and the perforations were not treated with reactive acids. The well flowed 1025 BOPD and 325 MCFGPD. Approximately 40% of the gas was nitrogen. After reperforation, the well had cumulative production of 70,000 BO before casing collapse occurred in February, 1997.

As part of the production operations conducted by Eagle Operating, Shell seismic data were obtained and reprocessed. These data revealed that structural relief locally existed on the Precambrian basement near the end of Deadwood deposition and locally during lower Winnipeg deposition.. A significant tectonic event occurred near the top of the Deadwood and coincides with a lower Ordovician plutonic event in the Williston Basin. This tectonism is reflected in local Precambrian remnants

that occur near the top of the Deadwood. These brecciated Precambrian remnants and blocks were originally interpreted to be impact ejecta.
Seismic mapping shows various types of structural and stratigraphic traps within the field. Recent drilling confirmed these anomalies and permitted integration of seismic signatures to rock distributions.

A horizontal well was attempted early in the modern development of the field, but met with mechanical failure. A directionally drilled well encountered lower Deadwood sandstones, but the formation was tight..

The field probably has an estimated minimum of 5 to 10 MMBO and 25 BCF natural gas (hydrocarbons). Further drilling will concentrate on newly refined seismic signatures of basement blocks and preserved Deadwood and Winnipeg sandstones.

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Microbial Control of Paraffin, Scale, Corrosion, Emulsion, & Hydrogen Sulfide

***Bill Botto**
Micro-TES, Inc.

Brent M. McCallick
Micro Well Services, Inc.

Microbial Control of Paraffin, Scale, Corrosion, Emulsion, & Hydrogen Sulfide

Abstract

Paraffin accumulations, corrosion, scale, and emulsions have historically resulted in significant expenses and reduced profitability for oil producers and operators. Traditional control methods such as hot oiling, chemical treating, and paraffin scraping are only modestly successful and often have serious long-term detrimental effects on the formation (especially in the case of hot oiling) and the productive life of the well.

Paragone™ is a microbial product designed to be used in a treatment program to remove and control paraffin, scale, emulsions, asphaltines, and H_2S. Paragone™ is composed of naturally occurring microorganisms suspended in an aqueous solution. Micro-TES, Inc. in San Antonio, Texas produces the product; Micro Well Services, Inc. distributes it in the United States. All of Micro-TES' products are non-toxic, non-flammable, non-combustible, non-hazardous, and non-pathogenic. Paragone™ will not harm plants or animals and requires no special permits to transport, use, or dispose. The safety advantages alone over traditional methods of well maintenance are significant. The *results* of our treatment programs show these products to be outstanding.

Paragone™ has been successfully used in over fifty formations including success with heavy crude and asphaltines.

Paraffin Reduction in the Wellbore Fluids

Turbulence in the wellbore fluids created by inflow from the formation and the pump action will disperse the Paragone™ solution throughout the well fluids. As the bacteria migrate and grow they **remove paraffin** deposits wherever they have accumulated throughout the entire pumping and collection systems. The metabolic processes of the bacteria degrade and resolubilize paraffin crystals with these beneficial results:

- The petroleum will not reform paraffin deposits at any point in the pumping system, the flow lines, the heater treater, or the storage tanks.
- The viscosity of the fluids will decrease, which can result in a proportional increase in the API gravity.

Paraffin Reduction in the Near Wellbore Area

Numerous studies of the effects of hot oiling over extended periods of time have pointed to the reduction of permeability and porosity of the formation at or near the well bore. Paragone™ bacteria are able to withstand extremes in pressure and temperature allowing them to **resolubilize paraffin deposits that are impeding flow to the wellbore**. The microbes will even remove the higher molecular weight paraffin that has a melting point above the formation temperature.

In instances where this type of paraffin accumulation is present, some increase in production may occur. This depends on many variables, the primary one being the available production left in the formation. In cases with extreme paraffin buildup the increase in production has been dramatic.

Paraffin in the Pumping and Storage Systems

Paragone™ treatments are designed to provide sufficient volumes of bacteria to clean paraffin from mud anchors, gas anchors, perforated nipples, pump valves, sucker rod strings, and tubing walls. Eventually the bacteria will colonize in the downstream production facilities cleaning out flow lines and storage tanks. BS & W, or tank bottoms, have been dramatically reduced by Paragone™ treatments. If there are tank bottom problems at a facility a separate treatment can be designed specifically for their reduction.

Emulsion Reduction – Carryover Elimination

Emulsions permanently break down or do not form at all due to the activities of the microbes at the oil water interface and surfactant production. The microbes reside in the water phase, concentrating and metabolizing at the oil water interface leading to rapid and effective treatment of emulsions. This is caused by reduction of the surface tension of the oil and the water, thus allowing separation by density.

The elimination of emulsions will eliminate carryover. **In many cases the most important production number, sales, will increase without any increase in total fluid production.**

Scale and Corrosion Inhibiting Processes

The active organisms in Paragone™ secrete and deposit a film of polysaccharide that forms a continual coating on well components. This coating **reduces scale and corrosion** as long as the augmentation of the organisms is maintained.

Scale Reduction

As previously stated, the bacteria produce surfactants (enzyme catalysts) that cause paraffin and other precipitates to go back into solution. They also reduce the free oxygen available, which inhibits oxidation reactions such as:

$FeSO_3 + O = FeSO_4$ (the conversion of iron sulfite to iron sulfate)

Iron sulfate is less soluble than iron sulfite. In the case of compounds containing calcium and sodium, the microbes use those ions in metabolic reactions. Metabolically produced polysaccharide films coat and prevent nucleation of scale.

Corrosion Reduction

The Paragone™ bacteria will scavenge the available oxygen thus making it less available for oxidation reactions such as corrosion. In addition the polysaccharide produced through metabolism will coat internal parts, placing a barrier between metal and corrosive elements. Paragon microbes competitively inhibit sulfur-reducing bacteria thus further discouraging corrosion.

Other Benefits and Uses of Microbial Treatment Programs

Production Stabilization

The most important result of our microbial treatment program may be production stabilization. Wells on a regular treatment program do not have the typical fluctuations in production rates. The **wells will produce at their potential** because the microbes work continuously against paraffin and scale accumulations. Production is further stabilized by a reduction in down time due to maintenance.

New applications and benefits are continually being discovered for our treatment programs. Some of these are described below.

Injection Treatments in Water Floods

Revolutionary results are being obtained in current injection treatments in water floods. Preliminary results indicate **profound decreases in water injection pressures, increased cleanup of produced water, near elimination of carryover, increased sales** and in some cases increased production. Additionally, the treatments in water floods are potentially tax deductible as tertiary recovery.

Frac Fluid, Polymer, and Soap Damage Reduction

The Paragone™ microbes will metabolize residue from frac fluid, polymers, and soaps **reversing the formation damage** caused by these materials.

Surfactants produced by the microbes also help to release drilling fluids that were trapped in high permeability zones within the formation. Wells as old as forty years have produced drilling mud after the first treatment.

Hydrogen Sulfide Reduction

Recently the reduction in H_2S has been substantiated in fields under treatment. The odor has disappeared and the sulfur content of the oil has been reduced. It has been confirmed that oil in one field has been changed from **sour to sweet**. The bacteria are removing the sulfur and using it as an electron receptor in their metabolism. Also, Paragon microbes competitively inhibit sulfur-reducing bacteria that may have been introduced into the formation. Research in this area is ongoing.

Salt Precipitation Reduction

Another recently discovered use and benefit of the Paragone™ microbial treatments is the **reduction of salt precipitation** in wells with severe salt problems. Success has been attained in keeping the salt in solution in the produced water eliminating the need for fresh water flushes. Wells that previously formed "saltcicles" on the surface equipment now show little or no evidence of the solid phase.

Inhibiting the Freezing of Facilities

Several years of use in the Rocky Mountain region has shown that wells on a treatment program have **fewer problems related to freezing**. During extreme freezing spells wells have been treated, shut in, and put back on production with no frozen fluids restricting or preventing movement. This is caused by the by-products of the metabolism, primarily alcohols and aldehydes.

Paragone™ Enhanced Oil Production

In addition to a maintenance procedure, Paragone™ can be used to enhance oil production. Larger treatments of Paragone™ and flush water are injected into the formation and the well is shut in for 7 days to two weeks. Any high molecular weight hydrocarbons i.e. paraffin and asphaltenes outside the wellbore are liquefied and allowed to pass into the wellbore thus cleaning-up the formation and **allowing more oil to flow**. Paragone™ will also reduce the surface tension of the oil in the formation thus allowing more oil to be released with resulting increased production. Increased gravity and decreased viscosity of produced oil are seen at the surface.

Gas Production

Since the relative permeability for gas is greater than that for oil it is not uncommon to see increases in gas production with or without an increase in oil production. Gas production changes are usually seen early in the treatment cycle.

If present, the hydrogen sulfide content is reduced in the gas as discussed previously. This can change the gas from sour to sweet. Paragone™ is effective whether the formation H_2S is indigenous or biogenic.

Starting A Treatment Program

If no chemical materials are being injected into the well bore **treatment can commence immediately**. If chemicals or toxic materials are in the system, or are part of the current treatment program, this should be discontinued for at least a week before the initiation of the Paragone™ treatment program.

Treatment Procedure

Paragone™ is usually applied to a well by pumping into the wellbore annulus. Little or no modification is required to perform the treatment program. The products are prepared for treatment with only potable water to prevent introduction of unwanted sulfur reducing bacteria into the formation. The normal treatment program consists of 75 to 300 gallons of bacteria, nutrient, and flush water. Treatment intervals vary from 30 to 90 days depending on well characteristics.

Special Problems Associated with Horizontal Wells

Horizontal wells exhibit many of the same problems with emulsion, salt blocks, paraffins, asphaltenes, and scale that vertical wells do. However, the treatment of these wells can be much more expensive and time consuming.

The conventional treatment of horizontal wells that have problems with paraffin, asphaltenes, and salt blocks is to use nitrogen and chemicals dispensed through a coiled tubing unit. This procedure is very expensive i.e. $20,000.00 to $50,000.00. These problems can be solved with Paragone™ for a fraction of the cost of using a normal pump and flush method.

The use of Paragone™ in horizontal wells will also solve problems of lost polymer-based mud and unrecovered frac gel. Removing these contaminates can greatly increase permeability into the horizontal well bore thus reversing the formation damage and increasing production.

Micro Well Services, Inc. Treatment Program Cost Effectiveness

Considering all factors associated with production, Paragone™ treatments are **extremely cost effective** when compared to conventional methods. Typical expenses that may be completely eliminated include hot oiling of tubing, flow lines, and tank batteries, stripping costs and rig time, chemical costs, and the costs of tank turndowns. Pumping equipment life cycles increase, and maintenance decreases, lowering the cost of operating the well.

The type, size, and cost of Paragone™ treatments depend on several factors including the oil and water production rates and the severity of the paraffin, scale, corrosion, emulsion, and/or H_2S problems as well as the down hole configuration. Each treatment program is individually designed and cost effectiveness is of primary importance.

Summary of Applicable Past and Current Treatments

Formations in the D J Basin, Powder River Basin, and Williston Basin:

Minnelusa (A & B)
Phosphoria
Tensleep
Arbuckle
Ft. Union
Sussex
Muddy
Parkman
Niobrara
Dakota
1st & 2nd Wall Creek
Lance
Sundance
Teapot
J Sand
D Sand
Codell
Codell/ Niobrara
Kansas City
Ocha-Louie
Red River
Madison
Charles "C" Tule Creek

Paragone™ Treatments China

Micro-TES' Australian office has been treating 120 oil wells for the China National Oil Company for over 2 years. The problems are extremely low gravity oil, high asphaltene, and some $CaCO_3$ scale. Results to date are approximately 70% success. Success is defined by China National Oil as a 20% increase in production. Their equipment is 1950's vintage with most originating in Russia. Several of the fields are under steam flood. Several groups of wells currently being treated with Paragone™ have had the steam injection shut off in their portion of the field. This saves energy and does not seem to effect the positive benefits of Paragone™ i.e. 20% increase in production, increased equipment life, decreased down time etc. Micro-TES' Australian office is currently preparing to treat several water floods in Northern China, as well as a new field near Mongolia that is just coming on line.

Paragone™ Use in Vietnam

Micro-TES' Australian office is currently preparing to treat a 51-Kilometer offshore pipeline located in Vietnam for Vietsovpetro, a Vietnamese and Russian consortium. The line is occluded with paraffin and asphaltene. Chemicals have been tried with no success. Micro-TES has performed bench tests with Paragone™ both in our lab and Vietsovpetro's lab and the results showed that Paragone™ could totally liquefy the paraffin/asphaltenes in the pipeline. This project should commence in the next 60 to 90 days.

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Landsat Lineament Zones in North Dakota

by

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Satellite images are useful in mapping regional tectonic patterns that are significant for horizontal drilling programs. Lineament zones mapped on Landsat images outline major lithosphere blocks. These zones are usually the sites of paleotectonic activity that influenced the deposition of reservoirs, seals, and source rocks. In addition, post-depositional deformation has made the lineament zones, corridors of structural anomalies and increased fracturing. Two examples of these generalizations are presented for the Williston Basin in North Dakota: 1) a series of six images document a regional lineament zone bounding the northeast margin and 2) an enlarged image shows more detailed structural features along the southern margin.

A preliminary interpretation of lineament zones along the northeast margin of the Williston Basin in north-central North Dakota has been prepared from six Landsat images. The images are standard enhancement products available from the EROS Data Center; they are multispectral scanner images in bands 5 & 7 and are at a scale of 1: 1,000,000 (1 inch = 16 miles). Linear features greater than 25 miles long that have been mapped on separate images by several workers, are taken as the significant components of a regional lineament zone. This zone trends northwest, is about 25 miles wide, and is located just to the northeast of the Missouri Coteau. Comparing this lineament zone with published maps, shows that it parallels structure contours on the top of the Madison Formation and that the subcrop of top of the Madison beneath Mesozoic rocks runs directly down the center of the lineament zone. Oil fields on the northeast basin margin tend to be concentrated within the northwest lineament zone in Canada, but also lie along a smaller northeast lineament zone in North Dakota.

On the southern margin of the Williston Basin, a multispectral scanner image in bands 2 & 4 at a scale of 1:250,000 (1 inch = 4 miles) is used to map linear features. Long linear features provide the basis for interpretation of a northwest lineament zone that corresponds with Cedar Creek Anticline and a northeast lineament zone that cuts the southern end of the anticline. Cedar Creek Anticline is a prominent feature that has had a long paleotectonic history, including uplift during the Laramide. The northeast lineament zone is a more subtle feature that is about 15 miles wide and extends along strike for more than 150 miles. Within the northeast lineament zone, three separate domains of Laramide deformation are recognized. At the intersection of the northeast lineament zone and Cedar Creek Anticline, there was compression; to the southwest in Montana there was right-lateral displacement; to the northeast in North Dakota there was left-lateral displacement with a significant component of extension. The northeast-trending lineament zone includes the horizontal Red River play in Bowman County and the Lodgepole fields in Stark County. The northwest-trending Cedar Creek Anticline has had a long history of oil and gas production. Both of these lineament zones are important production fairways that can be readily mapped on satellite images.

Mississippian Sherwood Shoreline Reservoirs As Horizontal Drilling Targets
Lucky Mound Field, McLean Co., North Dakota

by

Randolph B. Burke

Lucky Mound Field has produced over 1.4 million barrels of oil from finely dolomitized mudstones and peloidal packstones of the Sherwood interval. The reservoir appears to be partitioned on more than one scale: 1) the upper Sherwood from the lower Sherwood on the field scale, and 2) within the grainstone shoal facies on a localized scale. The upper Sherwood is separated from the lower Sherwood by a subaerial exposure surface that is tightly cemented on the tops of shoals where islands developed and more variably cemented off islands. Production data suggests that this exposure surface is sufficiently tight to essentially segregate the field into two reservoirs one in the upper Sherwood and one in the lower. However, karst processes on islands resulted in localized dissolution and the formation of solution cavities and collapse breccias. Horizontal solution cavities larger than the diameter of the core could reduce the success of water flood by channelizing the flow and reducing sweep efficiency. The relatively greater homogeneity of porosity and permeability in the upper Sherwood dolomudstone make them potential horizontal drilling targets. This is different than the majority of Sherwood reservoirs which produce from coarse pisolitic grainstones.

EXPLORATION TRENDS SOUTH OF THE BORDER

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www.willistonbasin.com

INTRODUCTION

Exploration in the Williston Basin has resulted in the discovery of sixteen new field discoveries, and over a dozen new pays were opened in existing fields since the last Horizontal Workshop. In this article we have included, for the Dakotas and Montana:

- An overview of major advances in the past year
- A listing of the latest available production for the 30 top North Dakota operators and a comparison with the 30 top producers in North Dakota fifteen months ago.
- *(Companies currently active in both Dakotas and eastern Montana are included in the registration packet and also available at MDS Booth.)*

HORIZONTAL DRILLING

Many Productive Horizons

This has been the biggest year for horizontal drilling in the Williston basin and a great variety of horizons have been tested in addition to the Red River "B." Twenty-nine horizontal wells were drilled and completed in North Dakota from horizons that include the Madison Group (Midale, Nesson, Wayne and others), the Silurian , and the Ordovician. Thirty horizontal wells, drilled and completed in Montana, included these pays: Mission Canyon members (Ratcliffe, Midale, Ratcliffe, McGowan), Charles, Dawson Bay, Nisku, Red River "C", Winnipeg.

Multi-lateral drilling has been tried successfully in a number of horizons, including the Red River "B," the Nesson Member of the Madison Group in Burke County and the Charles "C" Member in Dawson County. Samedan Oil has just completed a tri-lateral Charles "C" discovery about 14 miles northwest of Glendive, Montana, pumping 250 bbls of 31.5^{0} oil. The Samedan: Downs 43-15H is producing from open-hole horizontal legs in three porosity zones. In the last year Samedan completed three other horizontal "C" producers with rates ranging from 78 to 413 bopd.

Companies involved in horizontal drilling include: Ballantyne Oil, Burlington Resources, Citation, Columbus Energy, Continental Resources, The Exploration Co, Exxon, GeoResources, Petro-Hunt, Rigel, Samedan, Shell, Summit, UMC, Union Pacific, and Westport.

Red River "B"

The Red River "B" horizontal play in Cedar Hills Field continues to be an economic success in the southwestern portion of the field, approximately T129-131N, R101-107W. South of Marmarth, North Dakota, Continental Resources just completed the Turbiville 1-11 pumping 418 bopd, 57 bwpd, and the Big Gumbo Creek 1-8F, pumping 378 bopd, 62 bwpd. These rates are fairly typical of that area. In Cedar Hills Field 167 wells have been drilled and completed as producers; 209 wells are permitted and waiting on drilling.

The average ultimate primary recovery of the wells in the "sweet area," is estimated at 371,900 BO/well with a 14% primary recovery factor on 320 acre spacing, calculated with a normalized decline.[1] Burlington Resources and Continental Resources, the major players in the Red River "B" horizontal play in Bowman County, are allegedly planning to have unitization in order before the end of 1998 in order to maintain pressures and to have secondary recovery in place as soon as possible.

On the Cedar Creek Anticline, in Fallon and Wibaux Counties in Montana, 17 horizontal Red River "B" wells have been drilled in the past year.

VERTICAL WELLS

Fourteen fields were opened with vertical technology in North Dakota in the past year. Duncan discovered Livestock Field in the Lodgepole Formation within the Dickinson city limits. In Bowman County, the Exploration Co. (TXCO) opened Corey Butte Field with the Martha 1-36, producing 125 bopd in the Red River "C."

Red River "C" was the vertical target of successful wells drilled in Roosevelt, Sheridan, and Richland Counties, Montana, by Hugoton, Wyoming Resources, Panterra Petroleum, Chesapeake, Columbus Energy, Tipperary. Collins & Ware completed four Red River "C" wells, flowing from 81 - 234 bopd on their East Meridian Block B Prospect.

Summit Resources have been aggressively drilling in the Rabbit Hills and other areas this year and recently purchased the Montana properties of Equitable Resources.

In Meagher County, Hunt Oil drilled and cased the Galt 13-1, an 8000-ft Madison test in the disturbed belt 30 miles northeast of Helena,. This is a rank wildcat, 75 miles from the Sweetgrass Arch and the nearest production.

WILDCAT AREA PROSPECTS

Near Glacier National Park, K2 exploration is getting ready to drill its Chief Mountain and Morning Gun prospects, approximately 200,000 acres in the Disturbed Belt on the Blackfeet Reservation. These plays will evaluate gas in the Mississippian and Devonian formations, and hopefully carry the gas play southward from the Alberta foothills. K2 has a third prospect of 70,000 acres to target Devonian oil reserves. The Blackfeet Indian Tribe granted K2 development rights for 25 years, requiring K2 to drill a minimum of 15 wells over the next five years, with royalties on production set at 16.7 percent.

ADDITIONAL INFORMATION

For more specific information on any of these areas contact us at MDS. Our business is Williston Basin information, and if we can't provide what you need we can direct you to the person or agency that can help you. Of special note are our MDS-TOPS: a consistent dataset of digital log tops for North Dakota. We used them for the Red River contour map, and the Interlake/Red River Isopach on display on the MDS Horizontal Workshop display table.

April 17, 1998

Dr. Mary E. Bluemle
Minerals Diversified services, Inc.
www.willistonbasin.com

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[1] Luff Exploration and PTTC. 1997, Characterization of Red River Reservoirs and Development Strategies in Southwestern Williston Basin, DE-FC22-04BC14984. Available from PTTC at Colorado School of Mines, and from Sandra Mark (303-273-3107)

EXPLORATION TRENDS SOUTH OF THE BORDER

TOP 30 NORTH DAKOTA PRODUCERS*: ***MONTHLY PRODUCTION***

Prepared by MDS, Inc.

	November 1996		February 1998	
#	Operator	BBLS-Oil	Operator	BBLS-Oil
1	Burlington Res	416247	Burlington Res	394466
2	Amerada Hess	340166	Duncan Oil	366446
3	Continental Res	225126	Amerada Hess	327732
4	WH Hunt Trust	180428	Continental Resources	269592
5	Conoco	180141	Conoco	157247
6	Exxon USA	140473	WH Hunt Trust	142240
7	Westport O&G	117828	Westport Oil & Gas	139335
8	Citation Oil &Gas	71603	Exxon Company	135711
9	Berco Resources	49236	Citation Oil & Gas	68345
10	Hugoton Energy	45053	Berco Resources	54121
11	Panterra Petroleum	44813	Hugoton Energy	46656
12	Eagle Operating	39667	Ballantyne Oil	40551
13	Ballantyne Oil	37523	Panterra Petroleum	39841
14	Choctaw II O&G	34667	Choctaw II Oil & Gas	35782
15	Flying J Oil & Gas	33127	Eagle Operating	32869
16	JN Expl & Prod	31365	Flying J Oil & Gas	30223
17	Tidal Res (USA)	29478	Summit Resources	29872
18	True Oil	27326	Jn Expl & Prod	28942
19	Aviara Energy	24617	Total Minatome	26797
20	Samedan Oil	23084	Pioneer Natural Res Can.	24629
21	Equitable Res	22178	Aviara Energy	23864
22	Shell Western E&P	21998	Geo Resources	22565
23	ANR Production	21662	Samedan Oil	22038
24	Transtexas Gas	20704	Headington Oil	20231
25	Presidio Expl	20022	Luff Exploration	20188
26	Intoil	19604	MCNIC O&G Properties	20158
27	Condor Petroleum	18267	Collins & Ware	19680
28	Berenergy	17479	Shell Western E&P	18125
29	Total Minatome	16691	Condor Petroleum	16885
30	Geo Resources	16530	BTA Oil Producers	16285

*Source of production figures: NDIC: Oil & Gas Division Copyright 1998 Minerals Diversified Services, Inc.

Core List

#1,913

Amerada Petroleum Corp. - R. L. Stair #2
NW/4 SE/4 15-T161N-R79W
Newburg Field
Cored Interval = 3356-3379
Spearfish-Charles

#13,128

Axem Resources Inc. - Tracy Mountain #4-36
NW/4 NW/4 36-T139N-R101W
Fryburg Field
Cored Interval = 7969-7982
Tyler Sandstone

#10,646

Arco Oil & Gas Co. - #1-27 Irgens
NE/4 SW/4 27-T156N-R100W
East Fork Field
Cored Interval = 9204-9280
Rival beds

#10,536

Sun Exploration & Production Co. - R. G. Hicks #1
C N/2 SW/4 6-T151N-R102W
Elk Field
Cored Interval = 9455-9502
Central Basin Rival Facies

#4,092

Chandler & Associates, Inc. - Anderson #2
SE/4 NW/4 20-T163N-R82W
North Haas Field
Cored Interval = 3855-3874
Kisbey Sandstone

#6,981

Union Oil of California - A. C. Nelson #3-023
SW/4 SE/4 23-T163N-R83W
Haas Field
Cored Interval = 3975-4035
Glenburn beds

#12,356
CNG Producing Co. - Nelson #1-13
SW/4 SW/4 13-T159N-R82W
Elms Field
Cored Interval = 4493-4525
Wayne beds

#12,886
Shell Western E & P, Inc. - Connell 24-27
SE/4 SW/4 27-T144N-R102W
Buckhorn Field
Cored Intervals = 10497-10540 (vertical hole)
11781-11811 (horizontal hole)
Bakken Shale

#13,772
Continental Resources, Inc. - Peterson #1-26
NE/4 NW/4 26-T132N-R106W
Cedar Creek Field
Cored Interval = 9106-9128
Red River "B" zone

#14,521
Citation Oil & Gas Corp. - Stearns #14-15H
SW/4 SW/4 15-T129N-R106W
Cedar Hills Field
Cored Interval = 8272-8290
Red River "B" zone

#14,725
Eagle Operating, Inc. - E-M Larson #9-11R
NE/4 SW/4 9-T163N-R87W
Newporte Field
Cored Interval = 9418-9587
Deadwood Formation

BEST COPY AVAILABLE

WELL COMPLETION REPORT

10

1,913

CD-3

SEE INSTRUCTIONS OTHER SIDE

OPERATOR Amerada Petroleum Corporation FIELD Newburg
STREET P. O. Box 1009 POOL Spearfish-Charles
CITY Williston STATE North Dakota COUNTY Bottineau
LEASE NAME R. L. Stair WELL NO. 2 ACRES IN UNIT 80
LOCATION NW/4 SE/4 (¼ of ¼ Section) SEC 15 TWP 161-N RGE 79-W ELEVATION 1466 ~~[illegible]~~ KB)
PERMIT NO. 1925 ELECTRIC OR OTHER LOGS RUN? Schlumberger July 9 1958
NUMBER OF CRUDE OIL PRODUCING WELLS ON THIS LEASE, INCLUDING THIS WELL 2

DATA ON TEST

DATE TEST COMMENCED July 17 1958 HOUR 9 A.M. DATE TEST COMPLETED July 18 1958 HOUR 9 A.M.
LENGTH OF TEST 24 HOURS - MINUTES

FOR FLOWING WELL:
FLOWING PRESSURE ON CSG. ______ LBS./SQ. IN.
FLOWING PRESSURE ON TBG. Pumping LBS./SQ. IN.
SIZE TBG. 2-3/8 IN.
SIZE CHOKE ______ IN. TYPE CHOKE ______ (POS.ADJ.)
SHUT IN PRESSURE ______

FOR PUMPING WELL:
LENGTH OF STROKE 42 INCHES
NUMBER OF STROKES PER MINUTE 14
WORKING BARRELS 2" x 1¼" x 12'2" (SIZE IN.)
SIZE TBG. 2-3/8" OD EUE IN. NO. FT. RUN 3389

WAS THIS WELL FLOWED FOR THE ENTIRE DURATION OF THIS TEST WITHOUT THE USE OF SWAB OR OTHER ARTIFICIAL DEVICE? No

RESULT OF THIS TEST (BBLS. NET OIL PER 24 HRS.) 74
GAS-OIL RATIO OF THIS WELL IS Pumping (CU. FT. OF GAS PER BBL. OF OIL)
PERCENT WATER PRODUCED DURING THIS TEST 4
GRAVITY OF OIL PRODUCED DURING THIS TEST (CORRECTED TO 60° A.P.I.) 36.3

NAME OF PIPE LINE OR OTHER CARRIER Northwestern Refining Company
IF SHOT: DATE - NO. QTS. USED -
IF PERFORATED: NO. HOLES PER FT. Open Hole IF ACIDIZED: NO. GALS. USED 500
GEOLOGICAL FORMATION SHOT, PERFORATED OR TREATED Charles FROM 3389 FT. TO 3411 FT.
SHOOTING, PERFORATING OR TREATING COMPANY Howco
DATE WELL COMPLETED July 11 1958 HOUR WELL COMPLETED 11:00 A.M.
TOP OF PAY 3389 FT.

TOTAL DEPTH OF WELL 3411 FT.
PLUG BACK DEPTH -- FT.

WAS THIS WELL CORED? Yes WHAT INTERVALS? 3343 - 3411
GIVE DRILL STEM TEST DATA ON REVERSE SIDE OF THIS FORM

CASING RECORD

Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement	Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement
9-5/8	218		218		165						
5-1/2	3389		3389		250						

EXECUTED THIS 21 DAY OF July 1958 Amerada Petroleum Corporation (Company or Operator)

STATE OF North Dakota
COUNTY OF Williams } ss

R. O. Fuller (Signature) District Superintendent (Title)

Before me the undersigned authority, on this day personally appeared R. O. Fuller known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states that he is authorized to make this report and has knowledge of the facts stated herein and that said report is true and correct.

Subscribed and sworn to before me this the 21 day of July 1958

Fred L. Preston
Notary Public in and for Williams Co., North Dakota
My Commission expires ______

FRED L. PRESTON, Notary Public
My Commission Expires 11 30 1960

CD-4

SCHLUMBERGER

Laterolog
WITH GAMMA RAY

COUNTY BOTTINEAU
FIELD or LOCATION SEC.15-161N-79W
WELL R. L. STAIR #2
COMPANY AMERADA PETROLEUM CORPORATION

COMPANY AMERADA PETROLEUM CORPORATION
WELL R. L. STAIR #2
FIELD NEWBURG
LOCATION SEC.15-161N-79W NW SE
COUNTY BOTTINEAU
STATE NORTH DAKOTA

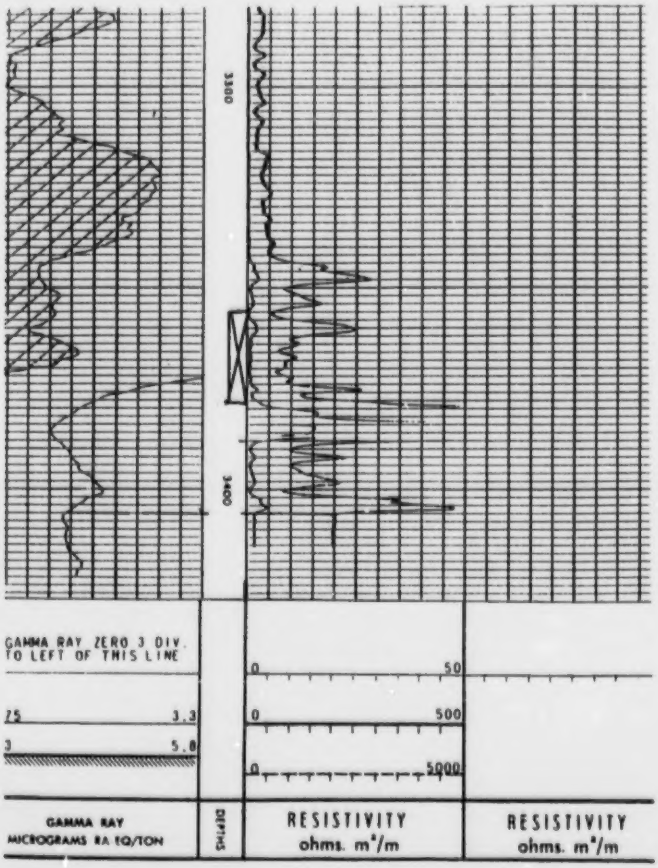
Other Surveys
ES MLL

Location of We
1913

Elevation: K.B.: 14
D.F.:
or G.L.: 14

Log Depths Measured From KB 11 Ft. above GL

RUN No.	ONE		
Date	7-7-58		
First Reading	3406		
Last Reading	217		
Feet Measured	3189		
Csg. Schlum.	217		
Csg. Driller	218		
Depth Reached	3408		
Bottom Driller	3411		
Mud Nat.	GYP BASE		
Dens. | Visc.	10.8 | 48	|	|
Mud Resist.	1.08 @ 65 °F	@ °F	@
" Res. BHT	.68 @ 103 °F	@ °F	@
" pH	-- @ °F	@ °F	@
" Wtr. Loss	7.6 CC 30 min	CC 30 min	CC 30
" Rmf M	.54 @ 103 °F	@ °F	@
" Rmc	@ °F	@ °F	@
Bit Size	7 7/8"		
Laterolog 3	a=12" ,l= 64"	a= ,l=	a= ,l=
Laterolog 7	a= ,n=	a= ,n=	a= ,n=
Opr. Rig Time	3 HRS.		
Truck No.	2768		
Recorded By	VANLUE		
Witness	GREGG		



CD-5

MICROLATEROLOG

SCHLUMBERGER

COUNTY BOTTINEAU
FIELD or LOCATION SEC. 15-161N-79W
WELL R. L. STAIR #2
COMPANY AMERADA PETROLEUM CORPORATION

COMPANY AMERADA PETROLEUM CORPORATION
WELL R. L. STAIR #2
FIELD NEWBURG
LOCATION SEC. 15-161N-79W
NW SE
COUNTY BOTTINEAU
STATE NORTH DAKOTA

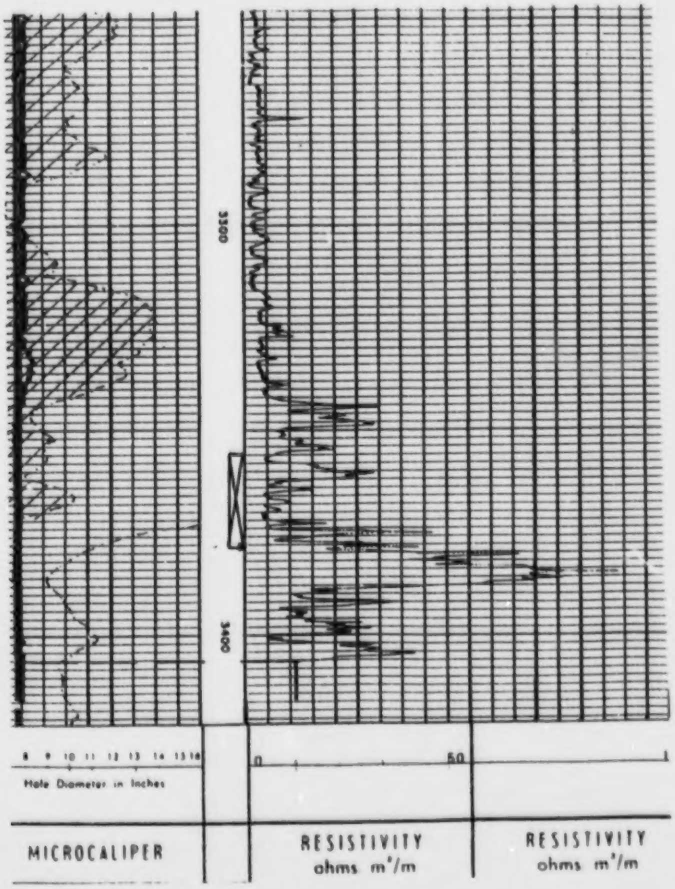
Other Survey
ES L-GR

Location of W
1913

Elevation: D.F.:
K.B.: 14
or G.L.: 14

Log Depths Measured From KB 11 Ft. above GL

RUN No.	ONE		
Date	7-7-58		
First Reading	3406		
Last Reading	2800		
Feet Measured	606		
Depth Reached	3407		
Bottom Driller	3411		
Mud Nat.	GYP BASE		
Dens. | Visc.	10.8 | 48	|	|
Mud Resist.	1.08 @ 65 F	@ F	@
" Res. BHT	.68 @ 103 F	@ F	@
" pH	-- @ F	@ F	@
" Wtr. Loss	7.6 CC 30 min	CC 30 min	CC 30
" Rmf M	.54 @ 103 F	@ F	@
" Rmc	@ F	@ F	@
Bit Size	7 7/8"		
SPCGS	9/16x9/16x9/16"		
Sonde Type	PML-A		
Pad Type	H		
Opr. Rig Time	1 HR.		
Truck No.	2768		
Recorded By	VANLUE		
Witness	GREGG		



CD-6

CONFIDENTIAL

TIGHT HOLE

LOCK UP

NW3c

Form 6

NORTH DAKOTA STATE INDUSTRIAL COMMISSION
Oil and Gas Division
900 East Boulevard, Bismarck, ND 58505

WELL COMPLETION OR RECOMPLETION REPORT
(Submit in Triplicate)

Well File No. 13128

Date Issued 1/31/91

Well Name & No. Tracy Mountain #4-36

Spacing (Unit Description) NW/4 - 160 Acres

Field Fryburg

Pool Heath Tyler

Wildcat, Development Development

County Billings

Designate type of completion: OIL WELL ☒ GAS WELL ☐ OTHER ________ SAME RESVR ☐

NEW WELL ☐ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☒ OTHER ________ DIFF. RESVR ☐

OPERATOR Axem Resources Incorporated

ADDRESS 7800 E. Union Ave. - Suite 1100 - Denver, CO 80237

LOCATIONS (Show quarter-quarter, footages, and section, township and range.)
At surface NW NW 600' FNL & 600' FWL - Section 36-T139N-R101W
At top prod. interval, reported below Same
At total depth Same

Date Spudded	Date TD Reached	Date Comp. (ready to prod.)	Elevation (KB,DF,GR)	Total Depth (MD & TVD)	Plug Back (TD,MD,TVD)
10-23-91	11-12-91	1-18-92	2,569' GR	9,350' KB	9,031' KB

Producing Interval(s), This Completion, Top, Bottom, Name (MD & TVD)	No. of DST's Run (see back)	Date Directional Survey Submitted
7,962-7,976'	1	NA

Type Electric and Other Logs Run (See instructions)	Was Well Cored
DLL/MSFL/GR/CAL - CDL/FDC/GR/CAL - BHC Sonic/GR CAL	Yes

CASING RECORD (Report all strings set in well)

Casing Size	Depth Set (MD)	Hole Size	Weight Lbs./Ft.	Sacks Cement	Amount Pulled
8-5/8"	1,976' KB	12¼"	24#	920	None
5½"	9,350' KB	7-7/8"	20#, 23#, 17#	2,150	None

LINER RECORD

Size	Top (MD)	Bottom (MD)	Sacks Cement	Screen (MD)
NA				

TUBING RECORD

Size	Depth Set (MD)	Packer Set (MD)
2-7/8"	7,715'	None

PERFORATION RECORD

Depth Interval (MD)	Holes per ft.	Size and Type	Purpose
7,962-7,976'	8	.45" Jet Charge	Production

ACID, SHOT, FRAC., CEMENT SQUEEZE, Etc.

Amt. & Kind of Material Used	Depth Interval (MD)
See Back	

PRODUCTION

Date First Production	Producing Method (Flowing, gas, lift, pumping - size & type of pump)	Well Status (Prod. or shut-in)
1/19/92	Pumping 2" Rod Pump	Producing

Date of Test	Hours Tested	Choke Size	Production For Test	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Oil Gravity - API (Corr.)
1/20/92	24	NA		329	74	85	42

Flow, Tubing Press.	Casing Pressure	Calculated 24-Hour Rate	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Gas-Oil Ratio
NA	40		329	74	85	225

Disposition of Oil & Gas (Purchaser and Transporter)	Test Witnessed By
Conoco Inc. (Both the Purchaser & Transporter)	Ivan Roller

LIST OF ATTACHMENTS

See original Completion Report for attachments - Dated 12/12/91.

Over to Complete Form

HALLIBURTON
LOGGING SERVICES, INC.

DUAL LATEROLOG
MICROSPHERICALLY FOCUSEI
LOG

FILING NO	COMPANY AXEM RESOURCES
	WELL TRACY MOUNTAIN #4-36
	FIELD TRACY MOUNTAIN
	COUNTY BILLINGS STATE NORTH DA

Location
NW/NW
660' FNL & 600' FWL
SEC 36 RGE 139N TWP 101W

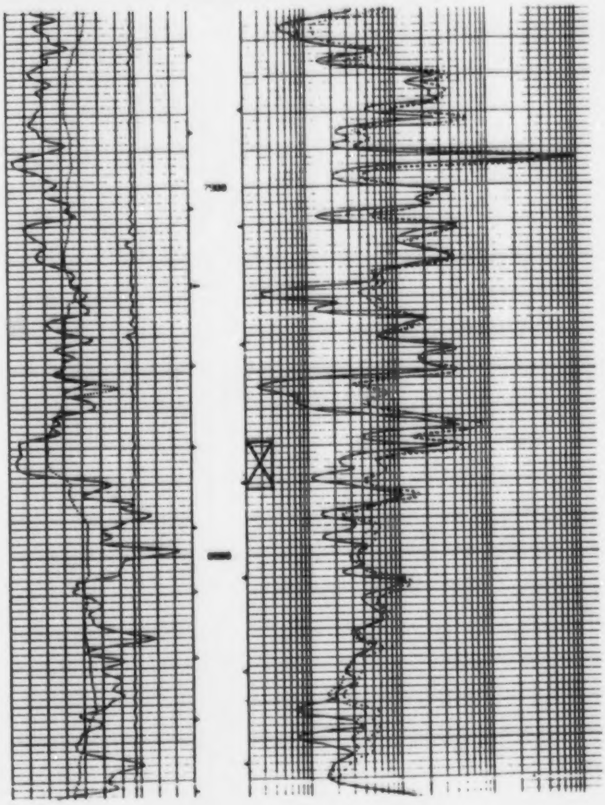
Other Services
CDL/DSN
BCS/2AC

Permanent Datum GROUND LEVEL Elev 2569'
Log measured from KELLY BUSHING 14 above perm. datum
Drilling measured from KELLY BUSHING

Elev. KB 2583
DF 2582
GL 2569

Date	11-13-91							
Run No	ONE							
Depth - Driller	9344							
Depth - Logger	9340							
Bottom Logged Interval	9338							
Top Logged Interval	90							
Casing - Driller	8.625 @ 1980		@		@		@	
Casing - Logger	1980							
Bit Size	7.87							
Type fluid in hole	SAT BRINE							
Density | Viscosity	10.6	40						
pH | Fluid Loss	7.0	11						
Source of Sample	FLOW LINE							
Rm @ Meas. Temp	.059 @ 61 °F		@	°	@	°	@	
Rmf @ Meas. Temp.	.045 @ 65 °		@	°	@	°	@	
Rmc @ Meas. Temp.	.091 @ 65 °		@	°	@	°	@	
Source: Rmf Rmc	MEAS	CHART						
Rm @ BHT	0.018 @ 220 °		@	°	@	°	@	
Time: End Circulation	0600 11-12-91							
Logger on bottom	0700 11-13-91							
Max. rec. Temp.	220 °			°		°		
Equip. No. | Location	7609	R.S.						
Recorded by	JOHNSON							
Witnessed by	MR GATHERIDGE		MR. GROTTE					

JAN 1992
N. D. OIL & GAS DIVISION



CD-8

HALLIBURTON LOGGING SERVICES, INC.

COMPENSATED DENSITY DUAL SPACED NEUTRON LOG

FILING NO

COMPANY AXEM RESOURCES

WELL TRACY MOUNTAIN #4-36

FIELD TRACY MOUNTAIN

COUNTY BILLINGS STATE NORTH D

Location
NW/NW
660 FNL & 600 FWL
SEC 36 RGE 139N TWP 101W

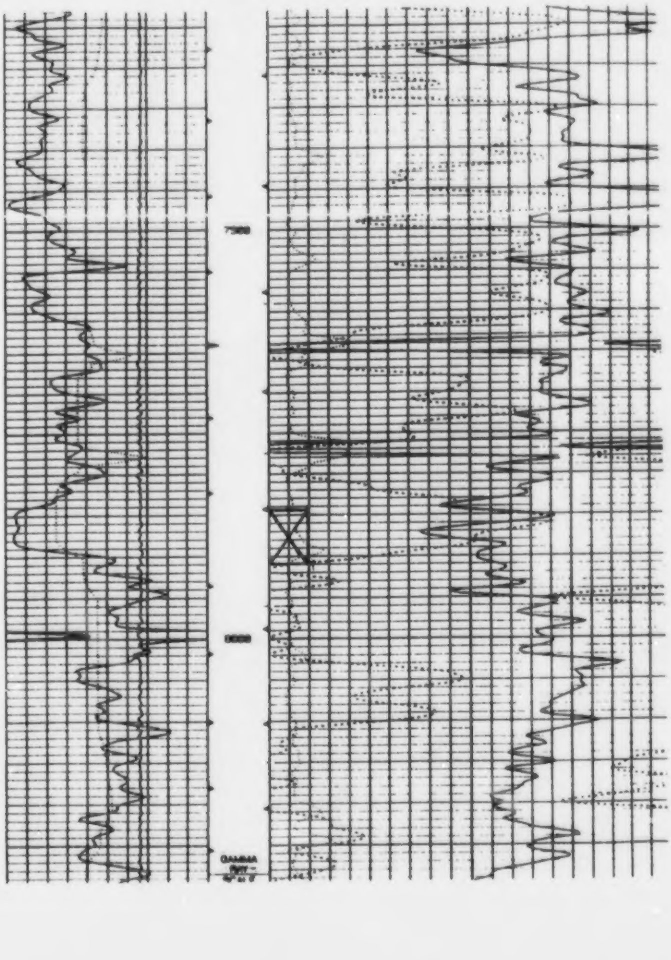
Other Services
DLL/MSFL
BCS/2AC

Permanent Datum GROUND LEVEL Elev 2569
Log measured from KELLY BUSHING 14 above perm. datum
Drilling measured from KELLY BUSHING

Elev KB 2583
DF 2582
GL 2569

Date	11-12-91	
Run No.	ONE	
Depth - Driller	9344	
Depth - Logger	9338	
Bottom Logged Interval	9336	
Top Logged Interval	7380	
Casing - Driller	8.625	@ 1980
Casing - Logger	NOT LOGGED	
Bit Size	7.87	
Type fluid in hole	SAT BRINE	
Density | Viscosity	10.6	40
pH | Fluid Loss	7.0	11
Source of Sample	FLOW LINE	
Rm @ Meas. Temp.	.059	@ 61 °F
Rmf @ Meas. Temp.	.045	@ 65 °
Rmc @ Meas. Temp.	.091	@ 65 °
Source: Rmf Rmc	MEAS	CHART
Rm @ BHT	0.018	@ 220 °
Time: End Circulation	0600	11-12-91
Time: Logger on bottom	2140	11-12-91
Max. rec. Temp.	220	
Equ No. | Location	7609	R.S.
by	JOHNSON	
y	MR GATHERIDGE	MR. GROTTE

JAN [illegible]
RECEIVED
N. D. OIL & GAS DIVISION



1312 CD-9

ROUTINE CORE ANALYSIS

AXEM RESOURCES INCORPORATED

Tracy Mountain 4-36 Well
Billings County, North Dakota

TerraTek Project No. 5079

SUBMITTED TO:

Axem Resources Incorporated
7800 East Union Avenue, Suite 1100
Denver, Colorado 80237

SUBMITTED BY:

TerraTek Geoscience Services
University Research Park
360 Wakara Way
Salt Lake City, Utah 84108

January 1992

TerraTek Geoscience Services®

University Research Park · 360 Wakara Way · Salt Lake City, Utah 84108 · (801) 584-2480 · FAX (801) 584-2408

AXEM RESOURCES INCORPORATED

Well:	Tracy Mountain 4-36	State:	North Dakota	Date:	3-JAN-1992
Field:	Tracy Mountain	County:	Billings	TTCS File #:	5079
Drilling fluid:	Salt Gel/Starch	Location:	Sec.36, T139N, R101W	Elevation:	2569' GL

FULL DIAMETER DEAN-STARK ANALYSIS

Sample Number	Depth (feet)	Permeability Kmax (md)	Permeability K-90 (md)	Permeability Vert (md)	Porosity %	Saturation Oil %	Saturation H2O %	Grain Density (gm/cc)	Lithology
Tyler Formation									
	7969.0-82.0								Shale; No analysis per client
1	7982.0-83.0	66.	64.	16.	12.6	25.2	21.7	2.65	Ss,ltgy,fgr,calc,mica
2	7983.0-84.0	59.	57.	14.	10.8	24.0	20.5	2.65	Ss,mgy,f-mgr,sil,sl/calc,styl
3	7984.0-85.0	1.6*	1.0*	.23	5.4	15.3	26.0	2.66	Ss,mgy,f-mgr,sil,sl/calc,styl
4	7985.0-86.0	.04	.04	.01	1.9	24.5	34.9	2.69	Ss,ltgy,vf-fgr,calc,fos
5	7986.0-87.0	.02	.02	<.01	1.3	22.0	39.5	2.69	Ss,mgy,vf-fgr,calc,fos,styl
6	7987.0-88.0	15.*	13.*	4.0	10.9	19.7	31.5	2.66	Ss,ltgy,fgr,sil,sl/calc,styl,if
7	7988.0-89.0	40.*	40.*	27.	11.1	26.8	22.5	2.65	Ss,ltgy,f-mgr,sil,sl/calc,mica,if
8	7989.0-90.0	28.*	27.*	7.1	11.0	23.0	30.0	2.64	Ss,ltgy,f-mgr,sil,sl/mica,styl
9	7990.0-91.0	17.	17.	3.2	10.7	24.7	25.6	2.66	Ss,mgy,fgr,sil,sl/calc,styl
10	7991.0-92.0	3.8*	2.2*	.28	8.8	21.5	42.3	2.70	Ss,mgy,fgr,dol,slty,styl,if
11	7992.0-93.0	5.7*	4.4*	.06	5.7	26.0	56.6	2.71	Ss,mgy,fgr,dol,slty,coal str,styl
	7993.0-94.7								Shale; No analysis per client
	7994.7-8001.0								Not Recovered
	8001.0-9130.0								Drilled Interval
Mission Canyon Formation									
	9130.0-9138.0								Anhydrite; No analysis per client
12	9138.0-39.0	.28	.19	.16	10.7	1.3	64.3	2.85	Dol,mgy,mxl,intxl,suc,bur
13	9139.0-40.0	2.0	1.9	1.2	17.8	14.9	36.1	2.84	Dol,brn,mxl,intxl,suc,anhy incl
14	9140.0-41.0	.11	.08	.01	2.2	18.4	69.3	2.89	Dol,ltgy,mxl,intxl,suc,slty

* - Rehydration crack affecting permeability

TerraTek Geoscience Services®

University Research Park · 360 Wakara Way · Salt Lake City, Utah 84108 · (801) 584-2480 · FAX (801) 584-2406

AXEM RESOURCES INCORPORATED

Well:	Tracy Mountain 4-36	State:	North Dakota	Date:	6-JAN-1992
Field:	Tracy Mountain	County:	Billings	TTCS File #:	5079
Drilling fluid:	Salt Gel/Starch	Location:	Sec.36, T139N, R101W	Elevation:	2569' GL

FULL DIAMETER DEAN-STARK ANALYSIS
DATA SUMMARY

Zone Number	Depth Interval (feet)	Number of Samples	Permeability Kmax (md)	Permeability K-90 (md)	Permeability Vert (md)	Porosity %	Saturation Oil %	Saturation H2O %	Grain Density (gm/cc)
Tyler Formation									
1	7982.0-85.0	3	42. [35.35]	41. [34.37]	10. [8.540]	9.6 [3.72]	21.5 [5.39]	22.8 [2.90]	2.65 [0.00]
2	7985.0-87.0	2	.03 [0.010]	.03 [0.011]	<.01 [0.006]	1.6 [0.41]	23.3 [1.69]	37.2 [3.23]	2.69 [0.00]
3	7987.0-91.0	4	25. [11.62]	24. [12.33]	10. [11.41]	10.9 [0.18]	23.6 [2.99]	27.4 [4.12]	2.65 [0.01]
4	7991.0-93.0	2	4.8 [1.319]	3.3 [1.565]	.17 [0.154]	7.3 [2.19]	23.7 [3.14]	49.5 [10.0]	2.71 [0.00]
Mission Canyon Formation									
5	9138.0-46.0	10	1.4 [1.865]	.89 [1.034]	.29 [0.405]	9.5 [4.43]	12.5 [7.62]	45.5 [14.8]	2.84 [0.02]
6	9148.0-56.0	8	.07 [0.068]	.05 [0.022]	.01 [0.013]	1.3 [1.38]	15.0 [7.34]	55.6 [22.9]	2.71 [0.02]

HORIZONTAL PERMEABILITY VS POROSITY

AXEM RESOURCES INCORPORATED
Tracy Mountain 4–36 Well
Tracy Mountain Field
Billings County, North Dakota
January 6, 1991

Depth Interval: 7982 to 7993 Feet
TTGS# 5079

Porosity (phi), %

Min	Max	Average
1.274	12.594	8.210

Permeability (Kh), md

Min	Max	Geo. Ave
0.024	66.291	4.879

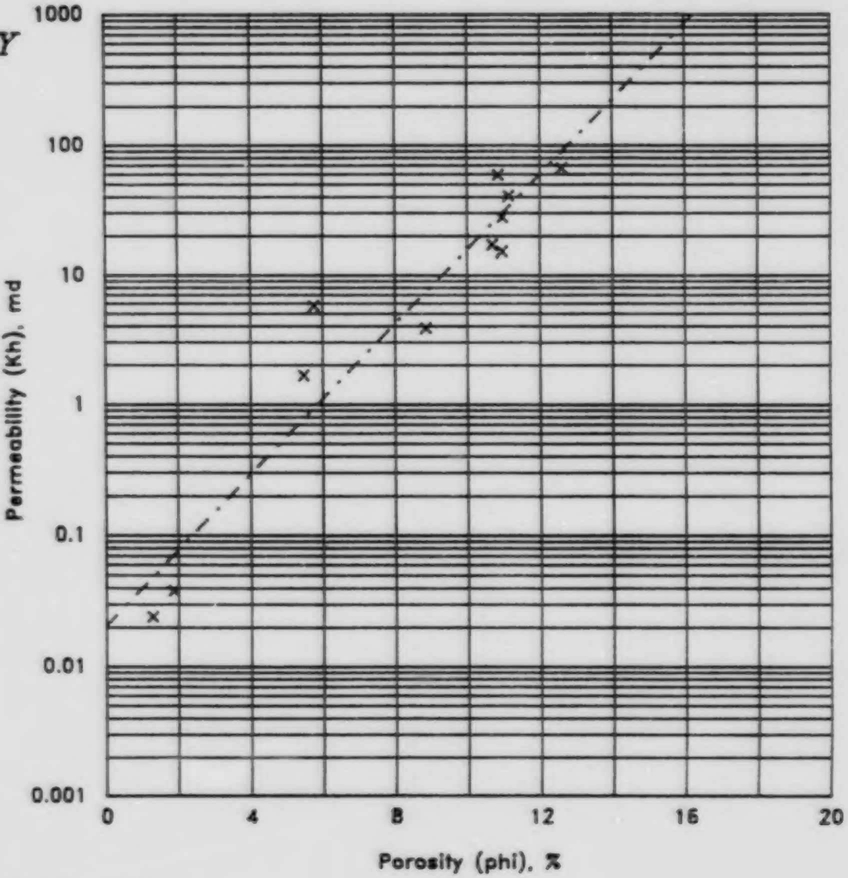
Equation of the Line

$\log Kh = \alpha \, phi + \beta$

$\log Kh = 0.2886 \, phi - 1.6815$

Correlation Coefficient : 0.957

Tyler Formation



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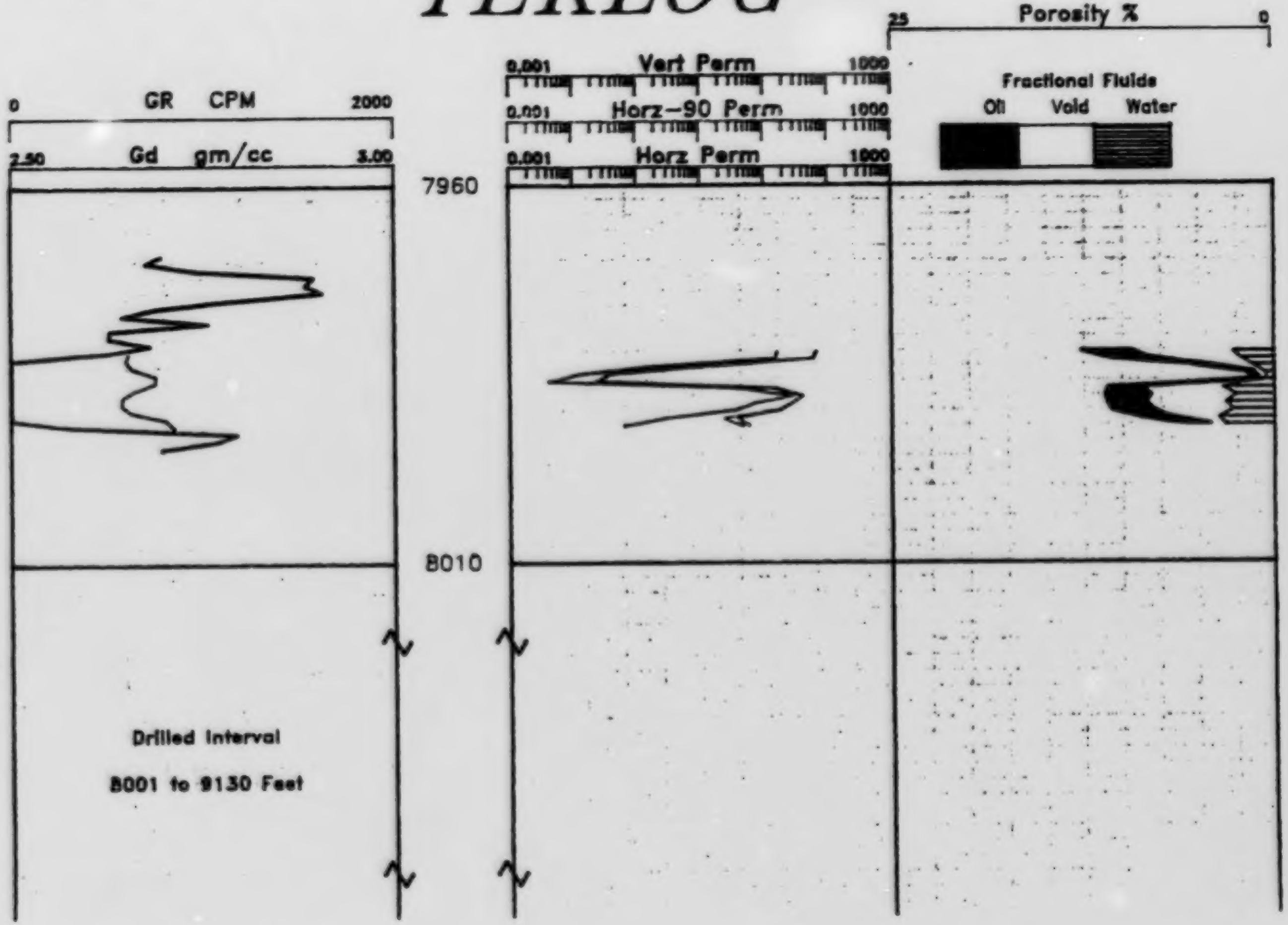
TERRA TEK GEOSCIENCE SERVICES
360 Wakara Way, SLC Utah 84108 (801) 584-2480

AXEM RESOURCES INCORPORATED
Tracy Mountain 4-36 Well

TEKLOG

January 6, 1991
TTGS File No.: 5079



CD-14

Form 6

NORTH DAKOTA STATE INDUSTRIAL COMMISSION

Oil and Gas Division
900 East Boulevard, Bismarck, ND 58505

CONFIDENTIAL

WELL COMPLETION OR RECOMPLETION REPORT AND LOG

(Submit in Triplicate)

TIGHT HOLE

Well File No.	[illegible]646
Date Issued	1-25-84
Well Name & No.	ARCO #1-27 Irgens
Spacing Designation	SW/4 Sec 27 160 acres
Field	New Field (Unnamed)
Pool	Madison ~~Mission Canyon~~
Wildcat, Development	Wildcat ✓
County	Williams

Designate type of completion: OIL WELL ☒ GAS WELL ☐ OTHER ______ SAME RESVR ☐

NEW WELL ☒ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ OTHER ______ DIFF. RESVR ☐

OPERATOR: ARCO Oil and Gas Company, Division of Atlantic Richfield Company

ADDRESS: P.O. Box 5540, Denver, Colorado 80217

LOCATIONS (Show quarter-quarter description and footage measurements.)

At surface: 1970' FSL & 1980' FWL Sec 27-156N-100W NE SW

At top prod. interval, reported below

At total depth: Approx the same

Date Spudded	Date TD Reached	Date Comp.(ready to prod)	Elevation (KB,DF,GR)	Total Depth (MD & TVD)	Plug Back (TD,MD,TVD)
2-19-84	5-12-84	5-31-84	2022'GL 2043'KB	13,710'	9550'

Producing Interval(s), This Completion, Top, Bottom, Name (MD & TVD)	No. of DST's Run (see back)	Date Directional Survey Submitted
Mission Canyon 9206' - 9226'	4	---

Type Electric and Other Logs Run (Circle those filed)	Was Well Cored
DLL-Micro/SFL; CNL; BHC	YES

CASING RECORD (Report all strings set in well)

Casing Size	Depth Set (MD)	Hole Size	Weight Lbs./Ft.	Sacks Cement	Amount Pulled
20"	80' GL	----------	----------Conductor----------	----------	----------
10-3/4"	4342'KB	14-3/4"	40.5#	2800	NONE
5-1/2"	9841'KB	8-3/4"	23#	2950	NONE

LINER RECORD

Size	Top (MD)	Bottom (MD)	Sacks Cement	Screen (MD)
----------	----NONE----	----------	----------	

TUBING RECORD

Size	Depth Set (MD)	Packer Set (MD)
2-7/8"	9143'	91[illegible]'

PERFORATION RECORD

Depth Interval (MD)	Holes per ft.	Size and Type	Purpose
9674'-9682'	4 SPF		
9708'-9718'	4 SPF		
9206'-9226'	4 SPF		

ACID, SHOT, FRAC., CEMENT SQUEEZE, Etc.

Amt. & Kind of Material Used	Depth Interval (MD)
100 sx Class "G" squeeze	9674'-82'
	and 9708'-18'
1600 gals acid + 3	9206'-9226'
ball sealers ea 42 gals	

PRODUCTION

Date First Production	Producing Method (Flowing, gas, lift, pumping - size & type of pump)	Well Status (Prod. or shut-in)
5-27-84	Swabbed and flowed	Producing

Date of Test	Hours Tested	Choke Size	Production For Test	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Oil Gravity - API (Corr.)
5-30-84	24 hrs	24/64"		662	278	27	3[illegible].6°

Flow. Tubing Press.	Casing Pressure	Calculated 24-Hour Rate	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Gas-Oil Ratio
220	Pkr		662	278	27	43[illegible]

Disposition of Oil & Gas (Purchased, used for fuel, vented, etc.)	Test Witnessed By
To be sold	Mel Palmer

LIST OF ATTACHMENTS

Daily Well History

Over to Complete Form

Schlumberger

DUAL LATEROLOG MICRO-SFL

COUNTY Williams
FIELD WILDCAT
LOCATION SEC.27-156N-100W
WELL IRGENS NO 1-27
COMPANY ARCO EXPLO. COMPANY

COMPANY ARCO EXPLORATION COMPANY
10646
WELL IRGENS NO.1-27
FIELD WILDCAT
COUNTY WILLIAMS STATE NORTH DAKOTA

RECEIVED N.D. [illegible]

LOCATION 1980 FWL 1970 FSL
NESW

API SERIAL NO	SEC	TWP	RANGE
	27	156N	100W

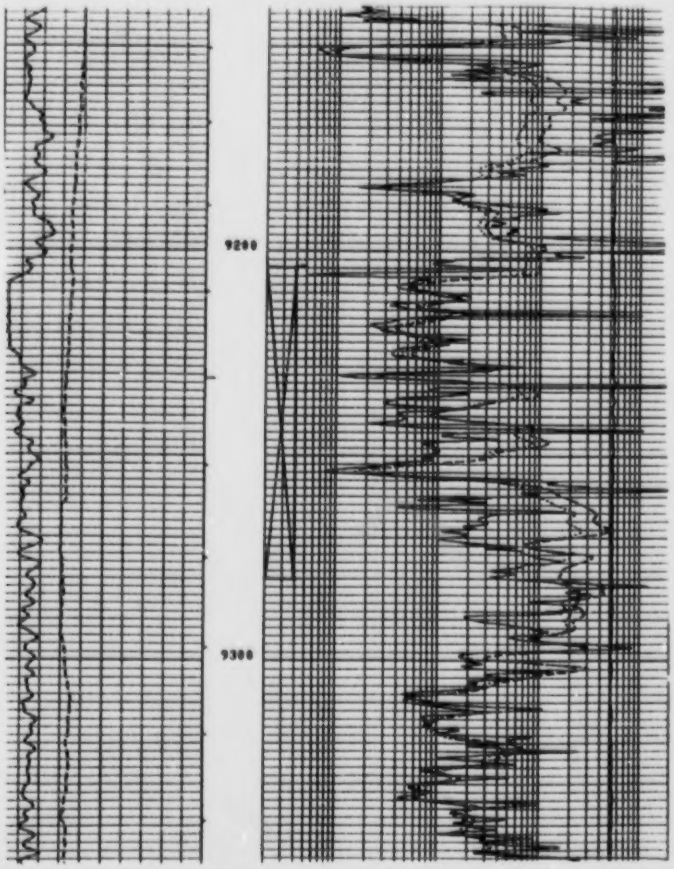
Other Services:
LDT/CNL
BHC/WF
LSS/WF HD1
HDT/DIR 4 A
CA

Permanent Datum: GL , Elev 2022
Log Measured From KB 21 Ft Above Perm Datum
Drilling Measured From KB

Elev.: K.B. 2043
D.F. ----
G.L. 2022

TIGHT HOLE

Date	2-25-84		4-8-84	
Run No.	ONE		TWO	
Depth—Driller	4342		9900	
Depth—Logger (Schl.)	4322		9894	
Btm. Log Interval	4321		9893	
Top Log Interval	0		4068	
Casing—Driller	20 @ 80	@	10-3/4 @ 4342	@
Casing—Logger	104		4338	
Bit Size	14-3/4		8-3/4	
Type Fluid in Hole	BRINE/NATIVE		SALT SATURATED	
Dens. | Visc.	10.3 | 32.0 S		10.3 | 38.0 S	
pH | Fluid Loss	6.8 | 80.0 ml C3	ml	6.5 | 13.8 ml C3	
Source of Sample	MUD TANK		MUD TANK	
Rm @ Meas. Temp.	.176 @ 66 °F	@ °F	.057 @ 64 °F	@
Rmf @ Meas. Temp.	.057 @ 66 °F	@ °F	.053 @ 64 °F	@
Rmc @ Meas. Temp.	.264 @ 66 °F	@ °F	.085 @ 64 °F	@
Source: Rmf | Rmc	MEAS | CALC	|	MEAS | CALC	|
Rm @ BHT	.116 @ 103 °F	@ °F	.021 @ 180 °F	@
TIME Circulation Stopped	0345		05.00	
TIME Logger on Bottom	0630		09.30	
Max. Rec. Temp.	103.0 °F	°F	180.0/181 °F	
Equip. | Location	8260 | WLSTN - 4309		8247 | WLSTN - 4309	
Recorded By	CAMPBELL		LEE	
Witnessed By	TODD		PARKS	



CD-16

Schlumberger

COMPENSATED NEUTRON LITHO DENSITY

COUNTY WILLIAMS
FIELD WILDCAT
LOCATION SEC.27-156N-100W
WELL IRGENS NO.1-27
COMPANY ARCO EXPLORATION CO.

COMPANY ARCO EXPLORATION COMPANY

10616

WELL IRGENS NO.1-27

FIELD WILDCAT

COUNTY WILLIAMS STATE NORTH DAKOTA

MAY 1984 RECEIVED N. D. OIL & GAS DIVISION

LOCATION 1980 FWL 1970 FSL
NE SW

API SERIAL NO	SEC	TWP	RANGE
	27	156N	100W

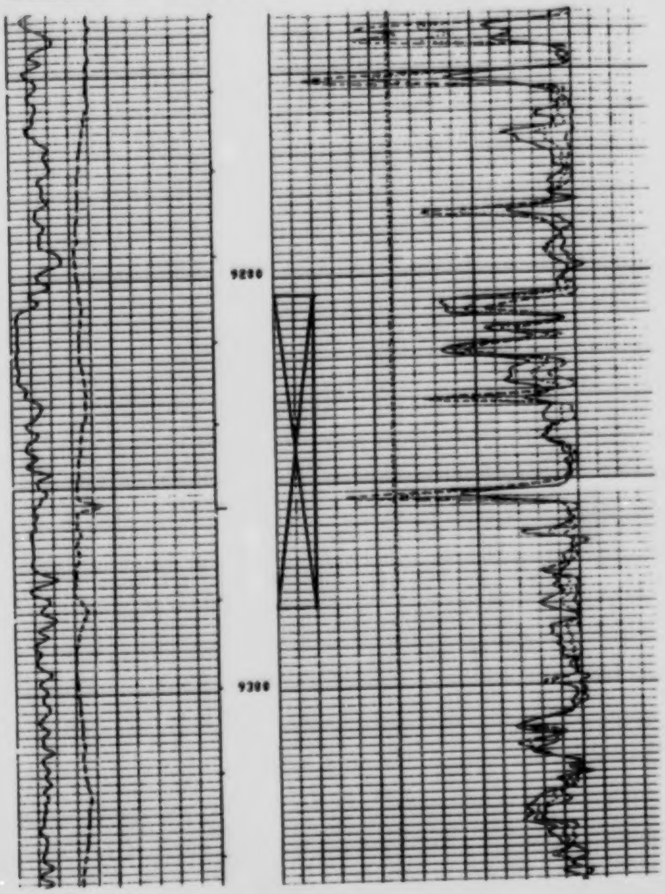
Other Services:
DLL/MSFL HD
BHC/WF DI
LSS/BHC WS
4 ARM CAL.

Permanent Datum GL Elev. 2022
Log Measured From KB 21 Ft. Above Perm. Datum
Drilling Measured From KB

Elev. KB 2043
DF --
GL 2022

TIGHT HOLE

Date	4-8-84		5-12-84	
Run No	ONE		TWO	
Depth - Driller	9900		13710	
Depth - Logger	9893		13690.9	
Btm. Log Interval	9890		13688	
Top Log Interval	4319		9689	
Casing - Driller	10-3/8 4342	@	10-3/4@ 4342	@
Casing - Logger	4338		4338	
Bit Size	8-3/4		8-3/4	
Type Fluid in Hole	SALT SATURATED		SALT MUD	
Dens. | Visc.	10.3 |	S	10.3 | 40.0	
pH | Fluid Loss	6.5 | 13.8 ml	C3 ml	6.3 | 7.6 ml	
Source of Sample	MUD TANK		MUD TANK	
Rm @ Meas. Temp.	.057 @64 F	@ F	.054 @73 F	@
Rmf @ Meas. Temp.	.053 @64 F	@ F	.047 @73 F	@
Rmc @ Meas. Temp.	.085 @64 F	@ F	.081 @73 F	@
Source: Rmf | Rmc	MEAS | CALC		MEAS | CALC	
Rm @ BHT	.021 @180 F	@ F	.018 @ 230°F	@
TIME Circulation Stopped	0500		5-11-2200	
TIME Logger on Bottom	1230		5-12-1200	
Max. Rec. Temp.	180 F	F	236 F	
Equip. | Location	8247 | WLSTN - 4309		8135 | WLSTN-4309	
Recorded By	LEE		FREBORG	
Witnessed By	PARKS		T. LENNEY	



Terra Tek Core Services®

University Research Park - 360 Wakara Way - Salt Lake City, Utah 84108 - (801) 584-2480 - TWX 910-925-5284

ARCO EXPLORATION COMPANY Date: 10 Jun 1984 TTCS File #: [illegible]

Well: [illegible] Jens No. 1-27

FULL DIAMETER AND PLUG ANALYSIS

Sample Number	Depth (feet)	Horz (md)	Permeability Horz-90° (md)	Vert (md)	Porosity (%)	Saturation Oil (%)	H2O (%)	Grain Density (gm/cc)	Lithology
[illegible]	9094.0-95.0	[illegible]			0.4	0.0	23.5	2.78	Dol,fxl,anhy incl.sl/sid
	9095.0 - 9099.0								Anhy
[illegible]	9099.0-00.0	0.01			13.9	0.0	25.3	2.80	Dol,suc,slty
[illegible]	9100.0-01.0	0.034			13.3	0.0	85.1	2.80	Dol,suc,slt lams
[illegible]	9101.0-02.0	0.01			13.5	0.0	38.3	2.80	Dol,suc,calc
	9102.0 - 9103.0								Dol,A/A,TBA
[illegible]	9103.0-04.0	<0.01			1.9	0.0	69.4	2.73	Ls,vfxl,sl/shy
	9104.0 - 9204.0								Drilled Interval

MISSION CANYON FORMATION

Sample Number	Depth (feet)	Horz (md)	Permeability Horz-90° (md)	Vert (md)	Porosity (%)	Saturation Oil (%)	H2O (%)	Grain Density (gm/cc)	Lithology
[illegible]	9204.0-05.0	<0.01			2.5	0.0	55.9	2.73	Ls,fxl,sl/shy,fos
[illegible]	9205.0-06.0	<0.01			3.0	0.0	64.8	2.75	Ls,vfxl,fos
[illegible]	9206.0-07.0	<0.01			2.9	0.0	61.7	2.75	Ls,vfxl,fos
[illegible]	9207.0-08.0	<0.01			1.2	0.0	61.4	2.75	Ls,vfxl,fos
[illegible]	9208.0-09.0	<0.01			2.1	0.0	50.8	2.74	Ls,vfxl,fos
[illegible]	9209.0-10.0	<0.01			2.7	0.0	47.3	2.74	Ls,vfxl,fos
[illegible]	9210.0-11.0	<0.01			3.1	0.0	44.0	2.75	Ls,vfxl
[illegible]	9211.0-12.0	<0.01			3.0	0.0	45.9	2.75	Ls,vfxl,fos
[illegible]	9212.0-13.0	<0.01			2.6	0.0	72.1	2.75	Ls,vfxl,sl/shy
	9213.0-14.0	<0.01			0.6	0.0	90.0	2.70	Ls,vfxl,shy
[illegible]	9214.0-15.0	<0.01			0.4	0.0	75.3	2.69	Ls,vfxl,shy,fos
[illegible]	9215.0-16.0	<0.01			0.7	0.0	94.5	2.70	Ls,vfxl,fos

[illegible] dehydrated rock

Terra Tek Core Services®

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ARCO EXPLORATION COMPANY Date: 10 Jun 1984 TTCS File #: 2
Well: [illegible]dens No. 1-27

FULL DIAMETER AND PLUG ANALYSIS

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90° (md)	Permeability Vert (md)	Porosity (%)	Saturation Oil (%)	Saturation H2O (%)	Grain Density (gm/cc)	Lithology	
[illegible]	9216.0-17.0	[illegible]+			1.0	0.0	47.9	2.71	Ls;vfxl,fos	
22P	9217.0-18.0	<0.01			0.8	0.0	45.7	2.70	Ls;vfxl,shy,fos	
23P	9218.0-19.0	<0.01			0.4	0.0	69.1	2.69	Ls;vfxl,slty,fos	
24P	9219.0-20.0	<0.01			0.3	0.0	75.8	2.69	Ls;vfxl,slty,fos	
[illegible]	9220.0-21.0	<0.01			0.6	0.0	86.5	2.70	Ls;vfxl,slty,fos	
[illegible]	9221.0-22.0	<0.01			0.8	0.0	57.2	2.69	Ls;vf-cxl	
27P	9222.0-23.0	<0.01			1.6	0.0	49.2	2.69	Ls;vf-cxl	
[illegible]	9223.0-24.0	0.02	<0.01		0.9	0.0	46.0	2.68	Ls;vfxl,sl/shy	
29P	9224.0-25.0	<0.01			0.9	0.0	47.5	2.69	Ls;vfxl,sl/shy,fos	
[illegible]	9225.0-26.0	0.17	0.01		2.6	13.8	31.3	2.71	Ls;vfxl-cxl,pp vdy	
[illegible]	9226.0-27.0	[illegible]	3.3		8.8	6.9	33.0	2.71	Ls;vfxl,pp vdy	
[illegible]	9227.0-28.0	21	20		10.9	10.6	34.0	2.71	Ls;vfxl,pp vdy	
[illegible]	9228.0-29.0	[illegible]	1.2		9.4	7.5	35.9	2.71	Ls;vfxl,sl/vdy	VF
[illegible]	9229.0-30.0	<0.01	*		1.8	0.0	49.1	2.70	Ls;vfxl	VF
[illegible]	9230.0-31.0	0.13	0.12		2.6	17.2	34.0	2.73	Ls;vf-cxl,sty	
[illegible]	9231.0-32.0	1.3	1.2		7.7	5.9	31.4	2.71	Ls;vfxl,pp vdy	
[illegible]	9232.0-33.0	17	17		10.8	9.7	29.4	2.71	Ls;vfxl,pp vdy	
[illegible]	9233.0-34.0	0.40	0.39		2.5	6.3	27.8	2.71	Ls;vfxl,pp vdy,sty	
[illegible]	9234.0-35.0	0.01	<0.01		3.2	9.7	37.3	2.71	Ls;vf-cxl,sty	
[illegible]	9235.0-36.0	230	0.02		6.5	9.3	31.4	2.71	Ls;vfxl-suc,pp vdy	VF
[illegible]	9236.0-37.0	31	*	0.20	10.8	7.0	31.5	2.71	Ls;vfxl-suc,vdy	VF
[illegible]	9237.0-38.0	106	106	30	13.3	7.3	39.0	2.70	Ls;vfxl-suc,vdy	

* Low Permeability - Sample not suitable for full diameter measurement
+ Horizontal dehydration crack

CD-18

Terra Tek Core Services®

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ARCO EXPLORATION COMPANY Date: 10 Jun 1984 TTCS File #: 2
Well: [illegible] No. 1-27

FULL DIAMETER AND PLUG ANALYSIS

Sample Number	Depth (feet)	Permeability Horz (md)	Horz-90° (md)	Vert (md)	Porosity (%)	Saturation Oil (%)	H2O (%)	Grain Density (gm/cc)	Lithology	
[illegible]	9238.0-39.0	2352	12		10.8	10.9	39.7	2.69	Ls;vfxl-suc,vgy	VF
[illegible]	9239.0-40.0	0.17	0.04		6.6	6.2	45.0	2.71	Ls;vfxl-suc,pp vgy	VF
[illegible]	9240.0-41.0	1.4	0.02		5.4	9.9	43.5	2.71	Ls;vfxl,pp vgy	VF
[illegible]	9241.0-42.0	1150	<0.01		4.2	0.0	72.0	2.74	Ls;vfxl,sty	VF
[illegible]	9242.0-43.0	0.09	0.02		5.1	0.0	50.8	2.71	Ls;vfxl,few pp vgs	VF
[illegible]	9243.0-44.0	0.12	0.03		6.4	0.0	52.8	2.71	Ls;vfxl	VF
[illegible]	9244.0-45.0	<0.01			6.2	0.0	34.9	2.71	Ls;vfxl	
[illegible]	9245.0-46.0	<0.01			3.3	0.0	54.5	2.70	Ls;vfxl	
[illegible]	9246.0-47.0	0.07	<0.01		0.7	2.1	39.5	2.69	Ls;vfxl	VF
[illegible]	9247.0-48.0	<0.01			0.4	0.0	72.0	2.71	Ls;vfxl	
[illegible]	9248.0-49.0	0.01			1.0	0.0	76.1	2.74	Ls;vfxl	
[illegible]	9249.0-50.0	0.02	0.01		11.5	0.0	91.7	2.79	Dol;suc,slty,calc	
[illegible]	9250.0-51.0	0.14+	0.03		5.6	0.0	92.0	2.77	Dol;vfxl,slty,calc	
[illegible]	9251.0-52.0	<0.01			0.2	0.0	90.6	2.70	Ls;vfxl	
[illegible]	9252.0-53.0	<0.01			0.2	0.0	89.1	2.71	Ls;vfxl	VF
[illegible]	9253.0-54.0	<0.01			2.1	0.0	48.0	2.74	Ls;vfxl	VF
[illegible]	9254.0-55.0	1.08	1.2		0.4	0.0	65.8	2.70	Ls;vfxl	VF
[illegible]	9255.0-56.0	0.02	0.02		0.3	0.0	99.3	2.70	Ls;vfxl	
[illegible]	9256.0-57.0	<0.01	<0.01		0.8	0.0	84.2	2.70	Ls;vfxl	
[illegible]	9257.0-58.0	<0.01			1.2	0.0	59.4	2.73	Ls;vfxl,slty	VF
[illegible]	9258.0-59.0	<0.01			5.3	0.0	46.6	2.74	Ls;vfxl,slty	VF
[illegible]	9259.0-60.0	<0.01			4.4	0.0	46.1	2.73	Ls;vfxl,slty	VF

+ Horizontal dehydration crack

Terra Tek Core Services®

University Research Park - 360 Wakara Way - Salt Lake City, Utah 84108 - (801) 584-2480 - TWX 910-925-5284

ARCO EXPLORATION COMPANY   Date: 10 Jun 1984   TTCS File #: 2
Well: [illegible]dans No. 1-27

FULL DIAMETER AND PLUG ANALYSIS

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90° (md)	Permeability Vert (md)	Porosity (%)	Saturation Oil (%)	Saturation H2O (%)	Grain Density (gm/cc)	Lithology	
95	9260.0-61.0	0.03	0.02		3.3	0.0	41.6	2.69	Ls;vfxl,slty	VF
96	9261.0-62.0	<0.01	<0.01		0.3	0.0	50.1	2.69	Ls;vfxl	
97	9262.0-63.0	<0.01	<0.01		0.3	0.0	63.5	2.70	Ls;vfxl	
98	9263.0-64.0	<0.01	<0.01		1.8	4.8	59.9	2.71	Ls;vfxl	
99F	9264.0-65.0	<0.01			0.8	0.0	49.1	2.69	Ls;vfxl	VF
100P	9265.0-66.0	<0.01			0.7	0.0	42.1	2.70	Ls;vfxl,slty	
101P	9266.0-67.0	<0.01			0.2	0.0	55.0	2.70	Ls;vfxl	
102P	9267.0-68.0	<0.01			0.3	0.0	58.1	2.69	Ls;vfxl	
103P	9268.0-69.0	<0.01			0.4	0.0	74.6	2.70	Ls;vfxl	
104P	9269.0-70.0	<0.01			1.4	0.0	72.2	2.73	Ls;vfxl	
105P	9270.0-71.0	<0.01			2.8	0.0	70.1	2.72	Ls;vfxl,slty	
106P	9271.0-72.0	<0.01			4.7	18.0	45.1	2.76	Ls;vfxl,dol	VF
107P	9272.0-73.0	<0.01			8.3	12.9	61.4	2.79	Dol;suc,calc	VF
108P	9273.0-74.0	0.11			15.0	21.6	49.4	2.82	Dol;suc	
109P	9274.0-75.0	<0.01			2.5	13.9	49.0	2.77	Ls;suc,dol	
110P	9275.0-76.0	<0.01			1.[illegible]	0.0	54.1	2.71	Ls;vfxl	
111P	9276.0-77.0	<0.01			0.5	4.7	57.6	2.70	Ls;vfxl	VF
112P	9277.0-78.0	<0.01			1.1	5.1	59.0	2.71	Ls;vfxl	VF
113P	9278.0-79.0	<0.01			2.1	3.6	55.0	2.71	Ls;vfxl	VF
114P	9279.0-80.0	<0.01			1.0	11.2	58.1	2.72	Ls;vfxl	VF

9280.0 - 13517.0   Drilled Interval

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HORIZONTAL PERMEABILITY
VS
POROSITY

ARCO EXPLORATION COMPANY

Irgens No. 1-27
Wildcat Field
Williams County, ND
10 Jun 1984
Mission Canyon Formation

Depth Interval : 9047 to 9280 feet

Permeability (K_h), mD

Min	Max	Geo. Ave
0.00	31.00	0.02

Porosity (ø), %

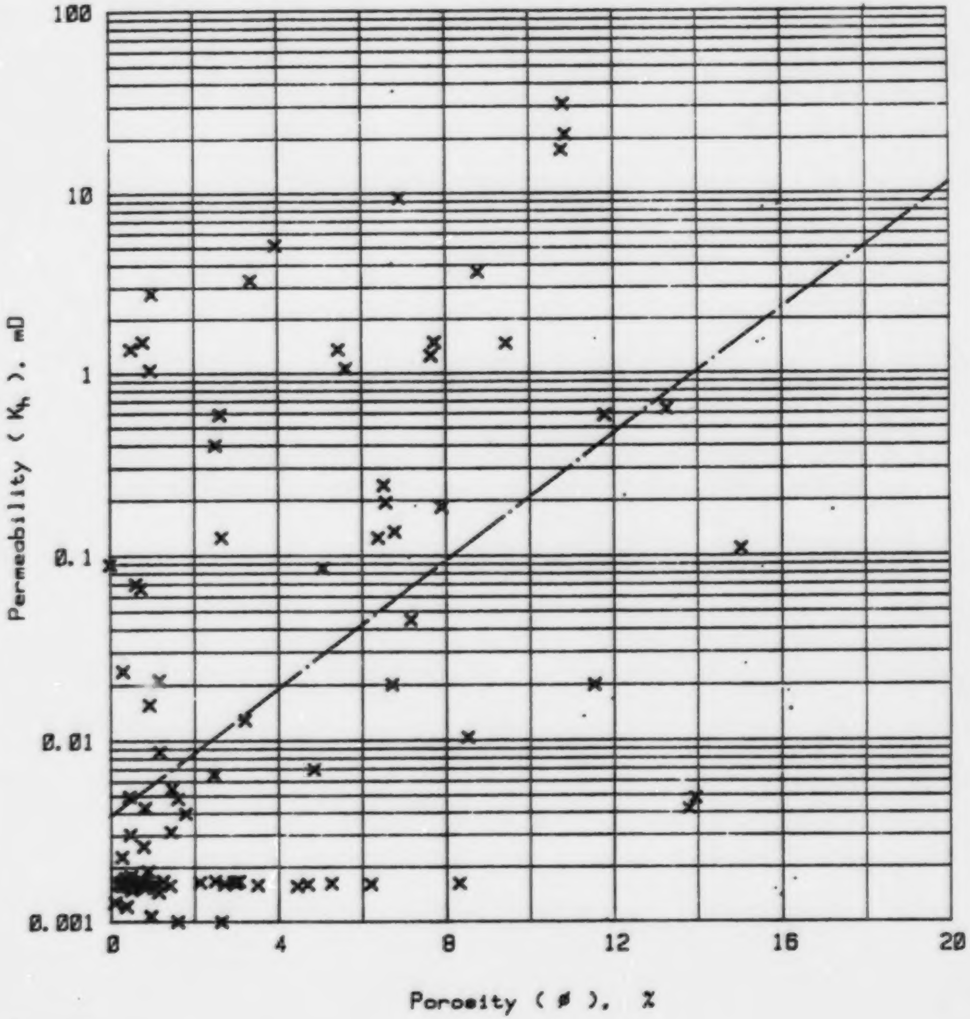
Min	Max	Average
0.0	15.0	3.4

Equation of the Line

$\text{Log } K_h = \text{Slope } ø + \text{Log of intercept}$

$\text{Log } K_h = .1733\ ø - 2.4104$

Correlation Coefficient : .517



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CD-22

FORM 6 (11)

North Dakota State Industrial Commission
Oil and Gas Division

MAR 1984
RECEIVED
N. D. OIL & GAS
DIVISION

WELL COMPLETION REPORT

SEE INSTRUCTIONS OTHER SIDE

OPERATOR Sun Exploration and Production FIELD Elk - E
STREET P.O. Box 5940 POOL ~~Mission Canyon~~ Madison
CITY Denver, STATE Colorado COUNTY McKenzie
LEASE NAME R.G. Hicks WELL NO. 1 ACRES IN UNIT 149.2
LOCATION ~~CNW SW~~ C N/2 SW SEC. 6 TWP. 151N RGE. 102W ELEVATION 2225 (DF, XXXXB.)
¼ of ¼ Section
PERMIT NO. 10536 ELECTRIC OR OTHER LOGS RUN? Yes 19 84
NUMBER OF CRUDE OIL PRODUCING WELLS ON THIS LEASE, INCLUDING THIS WELL 1

DATA ON TEST

DATE TEST COMMENCED 2-22 1984 HOUR 7 am. DATE TEST COMPLETED 2/23/ 1984 HOUR 7 a.m.
LENGTH OF TEST 24 HOURS -0- MINUTES.

FOR FLOWING WELL:
FLOWING PRESSURE ON CSG. ______ LBS./SQ. IN.
FLOWING PRESSURE ON TBG. 285 LBS./SQ. IN.
SIZE TBG. 2-7/8 IN.
SIZE CHOKE 14/64 IN. TYPE CHOKE Adj (POS. ADJ.)
SHUT IN PRESSURE 650#

FOR PUMPING WELL:
LENGTH OF STROKE ______ INCHES
NUMBER OF STROKES PER MINUTE ______
WORKING BARRELS ______ (SIZE IN.)
SIZE TBG. 2-7/8 IN. NO. FT. RUN 9582

WAS THIS WELL FLOWED FOR THE ENTIRE DURATION OF THIS TEST WITHOUT THE USE OF SWAB OR OTHER ARTIFICIAL DEVICE? Yes

RESULT OF THIS TEST (BBLS. NET OIL PER 24 HRS.) 112
GAS-OIL RATIO OF THIS WELL IS 727 (CU. FT. OF GAS PER BBL. OF OIL)
PERCENT WATER PRODUCED DURING THIS TEST 0
GRAVITY OF OIL PRODUCED DURING THIS TEST (CORRECTED TO 60° A.P.I.) 38°

NAME OF PIPE LINE OR OTHER CARRIER Powers Fuel
IF SHOT: DATE N/A NO. QTS. USED N/A
IF PERFORATED: NO. HOLES PER FT. 4 HPF IF ACIDIZED: NO. GALS. USED 5521.6
GEOLOGICAL FORMATION SHOT, PERFORATED OR TREATED ~~Miss Canyon~~ Madison FROM 9460 FT. TO 9482 FT.
SHOOTING, PERFORATING OR TREATING COMPANY Halliburton
DATE WELL COMPLETED 2/22 1984 HOUR WELL COMPLETED 7 A.M.
TOP OF PAY 9482 FT.

TOTAL DEPTH OF WELL 9582 FT.
PLUG BACK DEPTH 9546 FT.

WAS THIS WELL CORED? yes - 2 WHAT INTERVALS? 9455-92/9492-9502
GIVE DRILL STEM TEST DATA ON REVERSE SIDE OF THIS FORM.

CASING RECORD

Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement	Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement
9-5/8"	2235		2235		1352						
5-1/2	9582		9582		1472						

EXECUTED THIS 8th DAY OF March 1984 Sun Exploration and Production Co.
(Company or Operator)

Debra L. Roth Sr. Acctg. Ass't
(Signature) (Title)

STATE OF Colorado
COUNTY OF Arapahoe } ss

Before me the undersigned authority, on this day personally appeared Debra L. Roth known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states that he is authorized to make this report and has knowledge of the facts stated herein and that said report is true and correct.

Subscribed and sworn to before me this the 8 day of March 1984

Michele Leffler

My Commission expires 11/25/87 Notary Public in and for Arapahoe Co., Colorado

MICHELE LEFFLER
17294 E. KENYON DR.
AURORA, CO 80013

FINAL PRINTS
Schlumberger

DUAL LATEROLOG MICRO-S

CSU Field Log

COMPANY: SUN EXPLORATION & PRODUCTION COMPA

WELL: R.G.HICKS NO.1

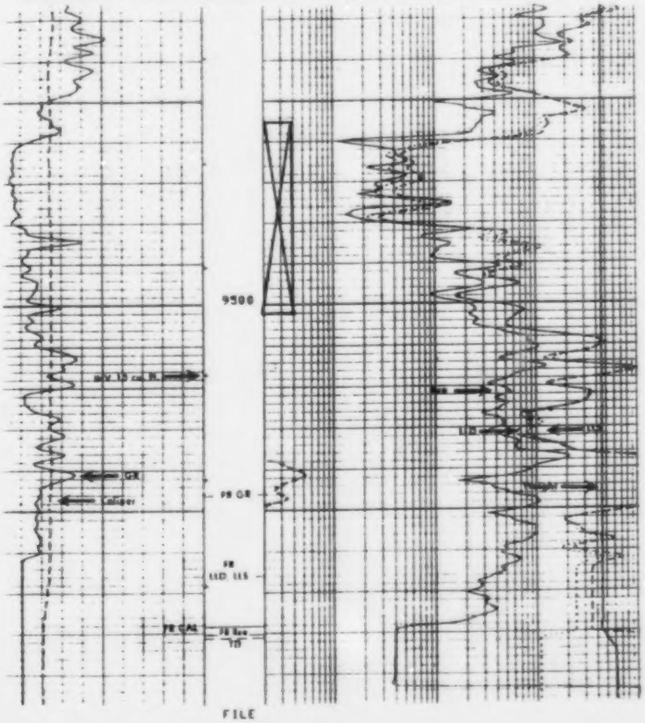
FIELD: ELK 10536
COUNTY: MCKENZIE
STATE: NORTH DAKOTA
NATION: U.S.A
LOCATION: NE SW (11)
1320 FEL - 1980 FSL
SEC: 6 TWP: 151N RGE:

L & GAS
ISION

PERMANENT DATUM: GROUND LEVEL ELEVATIONS
ELEV. OF PERM. DATUM: 2226.0 ' KB: 2244
LOG MEASURED FROM: KELLY BUSHI DF:
18.0 ' ABOVE PERM. DATUM GL: 2226
DRLG. MEASURED FROM: KELLY BUSHING

DATE: 19 JAN 1984
RUN NO: 1

DEPTH-DRILLER:	9600.0 '
DEPTH-LOGGER:	9581.0 '
BTM. LOG INTERVAL:	9580.0 '
TOP LOG INTERVAL:	2235.0 '
CASING-DRILLER:	2115 '
CASING-LOGGER:	2235 '
CASING:	9.625
WEIGHT:	36.00 LB/F
BIT SIZE:	8.75



4

LLD (OHMM) TENS(LB)
2000.0 200000 10000.
CALI(IN)
16.000 26.000
RXO (OHMM)
0.2000 200
CALI(IN)
6.0000 16.000
LLS (OHMM)
0.2000 200
GR (GAPI)
LLD (OHMM)

CD-24

FINAL PRINT
Schlumberger

COMPENSATED NEUTRON - LITHO DI

CSU Field Log

COMPANY: SUN EXPLORATION & PRODUCTION COMPANY

WELL: R.G.HICKS NO.1

FIELD: ELK
COUNTY: MCKENZIE
STATE: NORTH DAKOTA
NATION: U.S.A.
LOCATION: SW
1320 FEL - 1980 FSL
SEC: 6 TWP: 151N RGE: 10

1k536

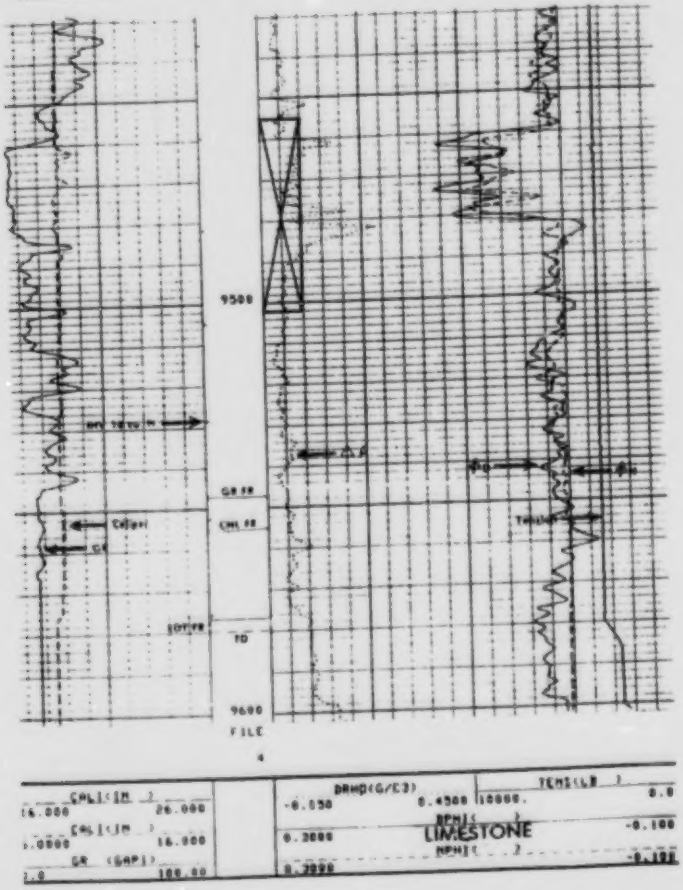
RECEIVED
N D OIL & GAS
DIVISION

PERMANENT DATUM: GROUND LEVEL ELEVATIONS-
ELEV. OF PERM. DATUM: 2226.0 ' KB: 2244.0
LOG MEASURED FROM: KELLY BUSHI DF:
18.0 ' ABOVE PERM. DATUM GL: 2226.0
DRLG. MEASURED FROM: KELLY BUSHING

DATE: 19 JAN 1984
RUN NO: 1

DEPTH-DRILLER: 9600.0 '
DEPTH-LOGGER: 9580.0 '
BTM. LOG INTERVAL: 9577.0 '
TOP LOG INTERVAL: 2235.0 '

CASING-DRILLER: 2115 '
CASING-LOGGER: 2235 '
CASING: 9.625
WEIGHT: 36.00 LB/F
BIT SIZE: 8.75



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

10536

CORE ANALYSIS REPORT

FOR ✓

SUN EXPLOR. & PROD. CO.

NO. 1 R. G. HICKS
ELK FIELD
MCKENZIE COUNTY, NORTH DAKOTA

ROCKY [illegible] PROJECT
FEB [illegible] 1984

MAR 1984
RECEIVED
N.D. OIL & GAS
DIVISION

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

SUN EXPLOR. & PROD. CO.
NO. 1 R. G. HICKS
ELK FIELD
MCKENZIE COUNTY, NORTH DAKOTA

DATE : 1-16-84
FORMATION : AS NOTED
DRLG. FLUID: SALT SAT NO OIL
LOCATION : NE SW SEC 6 T151N R102W

FILE NO : 3805-3365
ANALYSTS : R. E. B.
ELEVATION: 2244 KB
WILLISTON, NORTH DAKOTA

FULL DIAMETER BOYLE'S LAW ANALYSIS

FINAL REPORT

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN		DESCRIPTION
	9455.0-9492.0	MISSION CANYON FM. CORE NO. 1							
		1-16-84 CUT 37' REC 37'							
1	9455.0-56.0	1.50***	0.67	1.5	35.4	56.7	2.70		LM V/FN-FN XLN
2	9456.0-57.0	0.71***	0.65	1.2	0.0	65.3	2.69		LM V/FN-FN XLN FOSS
3	9457.0-58.0	4.60***	2.60	2.1	8.2	81.9	2.70		LM V/FN-FN XLN FOSS
4	9458.0-59.0	13. ***	7.10	1.9	21.6	74.0	2.69		LM V/FN XLN CARB
5	9459.0-60.0	14. ***	8.40	1.3	31.6	63.2	2.70		LM V/FN XLN CARB
6	9460.0-61.0	9.00***	3.90	1.4	31.2	62.3	2.69		LM V/FN XLN CARB
7	9461.0-62.0	3.90***	3.70	0.9	31.6	63.2	2.67		LM V/FN XLN CARB
8	9462.0-63.0	0.03	*	1.0	0.0	66.5	2.69		LM V/FN-FN XLN
9	9463.0-64.0	1.50***	1.10	1.2	57.3	32.7	2.69	VF	LM V/FN XLN CARB
10	9464.0-65.0	0.01	*	0.9	57.2	32.7	2.68	VF	LM V/FN XLN CARB
11	9465.0-66.0	0.14	*	1.1	41.8	50.1	2.69	VF	LM V/FN-FN XLN
12	9466.0-67.0	0.01	*	0.9	28.6	57.1	2.69	VF	LM V/FN XLN
13	9467.0-68.0	0.01	*	1.2	28.6	57.2	2.69	VF	LM V/FN XLN
14	9468.0-69.0	0.03	*	1.2	52.7	30.1	2.68	VF	LM V/FN XLN
15	9469.0-70.0	0.01	*	2.2	40.5	40.5	2.72	VF	LM V/FN-FN XLN
16	9470.0-71.0	0.03	*	1.2	63.8	28.4	2.69	VF	LM V/FN-FN XLN
17	9471.0-72.0	0.01	*	1.5	49.7	39.7	2.68	VF	LM V/FN-FN XLN
18	9472.0-73.0	1.70**	*	1.6	41.6	49.9	2.68	VF	LM V/FN-FN XLN
19	9473.0-74.0	0.01	*	1.5	16.6	66.4	2.68	VF	LM V/FN-FN XLN
20	9474.0-75.0	0.01	*	1.1	10.1	80.5	2.66		LM V/FN XLN
21	9475.0-76.0	1.50***	1.40	9.1	18.1	41.3	2.70		LM V/FN XLN-ALGAL CARB
22	9476.0-77.0	0.20	0.20	10.4	13.5	33.8	2.69		LM V/FN XLN-ALGAL CARB VUGGY
23	9477.0-78.0	0.01	*	6.6	0.0	67.3	2.72	VF	LM V/FN XLN

These analyses, opinions or interpretations are based on observations and materials supplied by the client to whom, and for...

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

SUN EXPLOR. & PROD. CO.
NO. 1 R. G. HICKS

DATE : 1-16-84
FORMATION : AS NOTED

FILE NO : 3805-3365
ANALYSTS : R. E. B.

FULL DIAMETER BOYLE'S LAW ANALYSIS

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN		DESCRIPTION
24	9478.0-79.0	0.01	*	4.6	2.6	63.3	2.68	VF	LM V/FN XLN
25	9479.0-80.0	0.31	*	7.2	0.0	82.7	2.70	VF	LM V/FN XLN
26	9480.0-81.0	7.00	4.90	10.2	7.0	28.2	2.71		LM V/FN XLN-ALGAL CARB VUGGY
27	9481.0-82.0	2.40	2.00	10.3	13.9	30.1	2.71		LM V/FN XLN-ALGAL CARB VUGGY
28	9482.0-83.0	1.80	*	9.1	3.1	39.9	2.70	VF	LM V/FNN XLN SCAT VUGS
29	9483.0-84.0	0.45	*	8.4	13.7	32.0	2.70	VF	LM V/FN XLN-ALGAL CARB VUGGY
30	9484.0-85.0	0.30	*	7.3	7.4	51.2	2.70	VF	LM V/FN XLN-ALGAL SCAT VUGS
31	9485.0-86.0	0.14	*	8.0	2.2	67.4	2.70	VF	LM V/FN XLN-ALGAL SCAT VUGS
32	9486.0-87.0	5.50	0.23	9.0	2.9	76.5	2.72	VF	LM V/FN XLN-ALGAL SCAT VUGS
33	9487.0-88.0	0.47	*	11.0	5.7	40.9	2.70	VF	LM V/FN XLN-ALGAL VUGGY
34	9488.0-89.0	0.98	*	9.7	2.3	50.3	2.70	VF	LM V/FN XLN-ALGAL VUGGY
35	9489.0-90.0	0.01	*	6.1	6.4	46.1	2.68	VF	LM V/FN XLN-ALGAL SCAT VUGS
36	9490.0-91.0	0.01	*	7.8	0.0	69.4	2.71	VF	LM V/FN XLN
37	9491.0-92.0	10.	*	7.8	1.5	48.9	2.71	VF	LM V/FN XLN-ALGAL SCAT VUGS

9492.0-9502.0 MISSION CANYON FM. CORE NO. 2

1-17-84 CUT 10' REC 10'

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN		DESCRIPTION
38	9492.0-93.0	0.09	*	4.6	6.2	35.0	2.70	VF	V/FN XLN-ALGAL SCAT VUGS
39	9493.0-94.0	0.01	*	2.0	0.0	85.9	2.69	VF	LM V/FN XLN
40	9494.0-95.0	0.01	*	1.3	0.0	90.8	2.69	VF	LM V/FN XLN
41	9495.0-96.0	0.01	*	1.0	0.0	75.1	2.69	VF	LM V/FN XLN
42	9496.0-97.0	0.01	*	0.7	0.0	67.3	2.69	VF	LM V/FN XLN
43	9497.0-98.0	0.07	*	2.1	0.0	70.9	2.75	VF	LM V/FN XLN
44	9498.0-99.0	0.01	*	0.9	0.0	65.8	2.70	VF	LM V/FN XLN
45	9499.0-00.0	0.01	*	0.9	0.0	70.7	2.70	VF	LM V/FN XLN
46	9500.0-01.0	0.01	*	0.9	0.0	66.8	2.70	VF	LM V/FN XLN
47	9501.0-02.0	0.01	*	0.9	0.0	69.7	2.70	VF	LM V/FN XLN

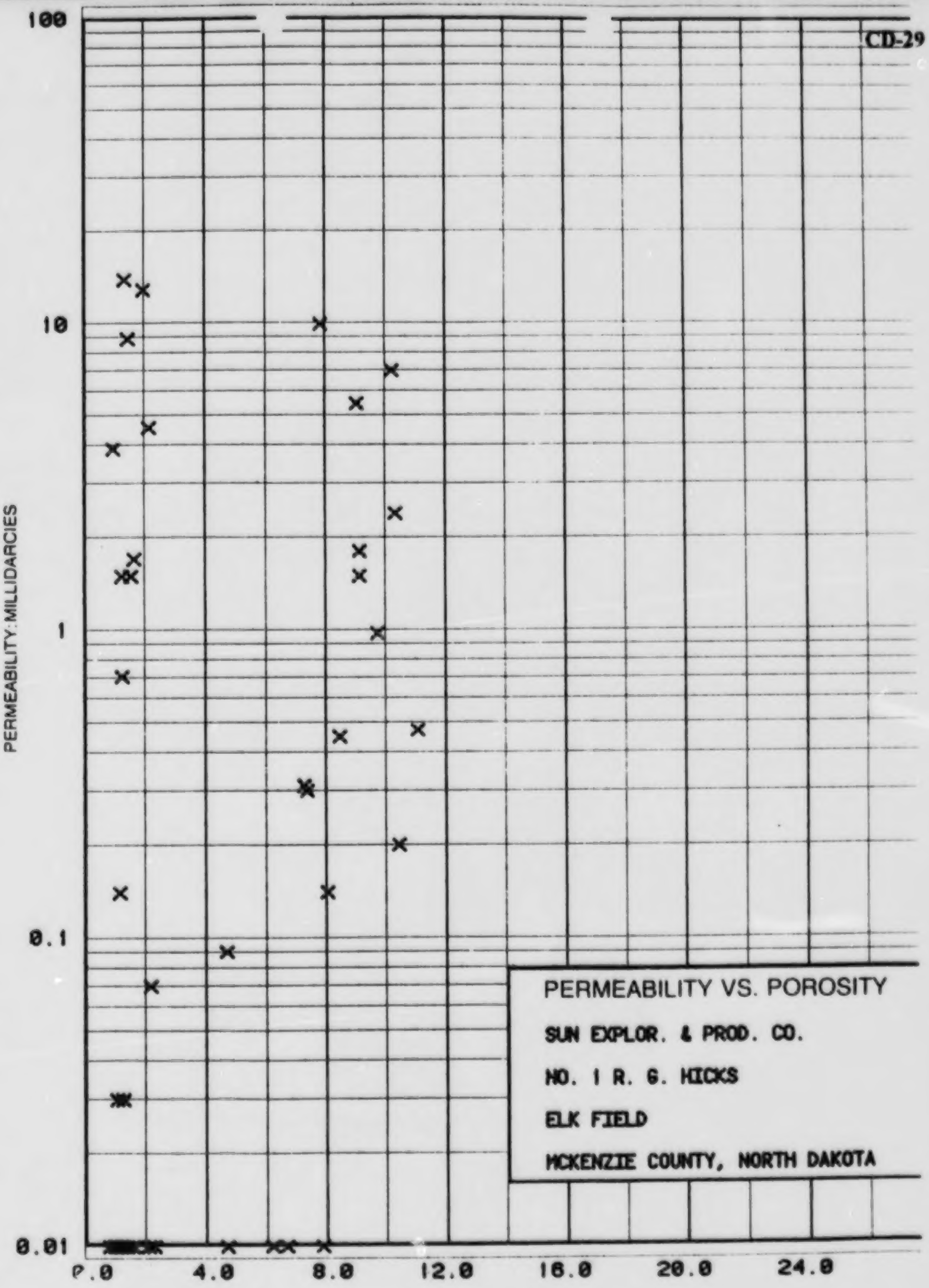
VF INDICATES VERTICAL FRACTURE
* SAMPLE NOT SUITABLE FOR FULL DIAMETER ANALYSIS
** DENOTES FRACTURED PERM SAMPLE
*** DENOTES LAMINAE

These analyses, opinions or interpretations are based on observations and materials supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted); but Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or representations, as to the productivity, proper operations, or profitableness of any oil, gas or other mineral well or sand in connection with which such report is used or relied upon.

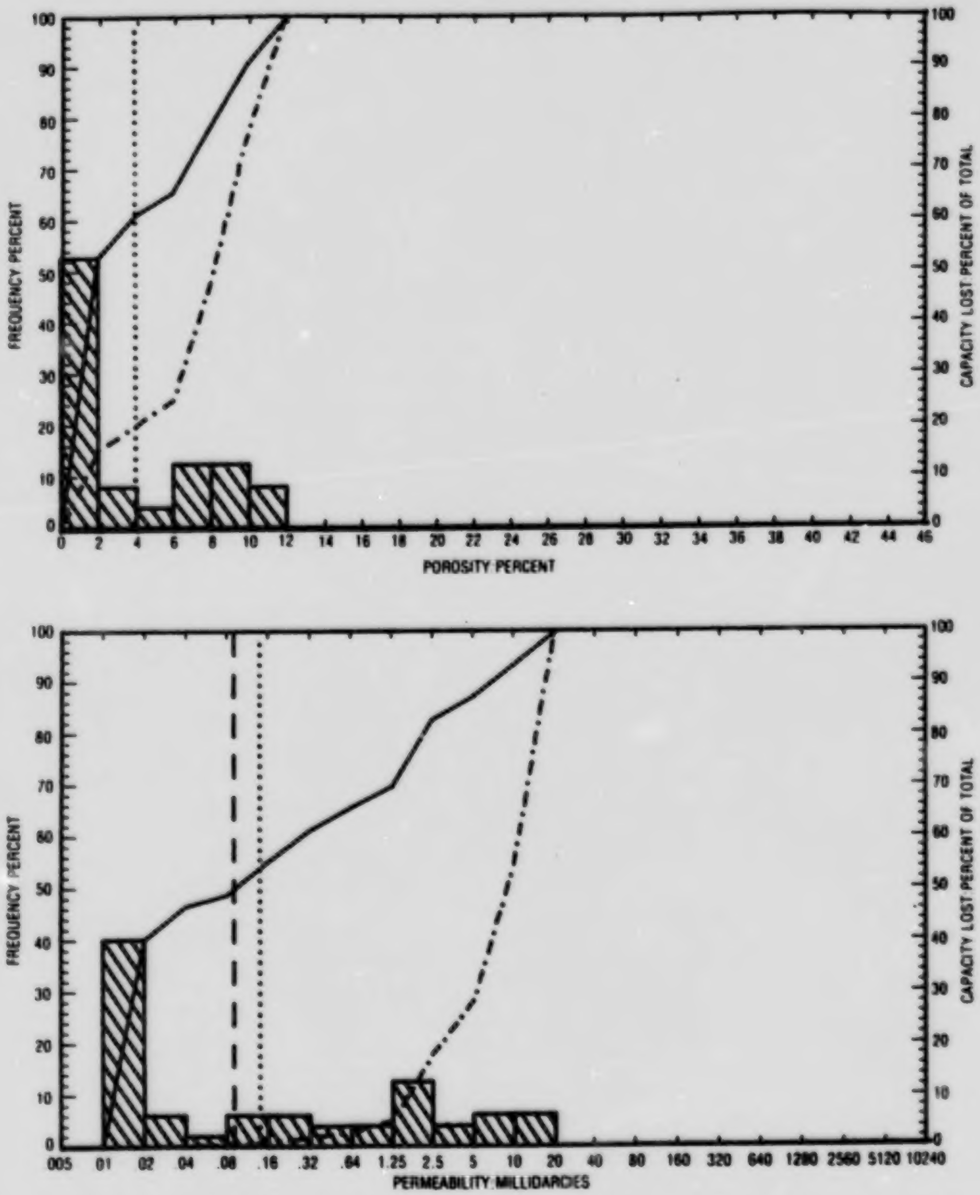
CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

```
SUN EXPLOR. & PROD. CO.          DATE         : 1-16-84                     FILE NO.    : 3805-3365
NO. 1 R. G. HICKS                FORMATION    : AS NOTED                    ANALYSTS    : R. E. B.

                                *** CORE SUMMARY AVERAGES FOR 1 ZONE ***

                                  DEPTH INTERVAL:   9455.0 TO  9502.0

          FEET OF CORE ANALYZED :   47.0     FEET OF CORE INCLUDED IN AVERAGES:   47.0

               -- SAMPLES FALLING WITHIN THE FOLLOWING RANGES WERE AVERAGED --

          PERMEABILITY MAXIMUM RANGE (MD.)        :   0.01 TO    15.   (UNCORRECTED FOR SLIPPAGE)
          HELIUM POROSITY RANGE (%)               :   0.6  TO   100.0
          OIL SATURATION RANGE (%)                :   0.0  TO   100.0
          WATER SATURATION RANGE (%)              :   0.0  TO   100.0

          SHALE SAMPLES EXCLUDED FROM AVERAGES.

                              AVERAGES FOR DEPTH INTERVAL:   9455.0 TO  9502.0

AVERAGE PERMEABILITY (MILLIDARCIES)                  PRODUCTIVE CAPACITY (MILLIDARCY-FEET)
   ARITHMETIC PERMEABILITY             :   1.7          ARITHMETIC CAPACITY                    :   82.
   GEOMETRIC PERMEABILITY              :  0.14          GEOMETRIC CAPACITY                     :   6.4
   HARMONIC PERMEABILITY               :  0.02          HARMONIC CAPACITY                      :   1.1
   GEOMETRIC MAXIMUM & 90 DEG PERM.    :  0.03          GEOMETRIC MAXIMUM & 90 DEG CAPACITY:   1.5

AVERAGE POROSITY (PERCENT)             :   3.9       AVERAGE TOTAL WATER SATURATION         :  51.4
                                                        (PERCENT OF PORE SPACE)

AVERAGE RESIDUAL OIL SATURATION        :   9.7       FULL DIAMETER ANALYSIS NO INTERPRETATION
   (PERCENT OF PORE SPACE)
```

These analyses, opinions or interpretations are based on observations and materials supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted); but Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or


100
10
1
0.1
0.01
PERMEABILITY:MILLIDARCIES
0.0
4.0
8.0
12.0
16.0
20.0
24.0
PERMEABILITY VS. POROSITY
SUN EXPLOR. & PROD. CO.
NO. 1 R. G. HICKS
ELK FIELD
MCKENZIE COUNTY, NORTH DAKOTA

CD-30



PERMEABILITY AND POROSITY HISTOGRAMS

SUN EXPLOR. & PROD. CO.
NO. I R. G. HICKS
ELK FIELD
MCKENZIE COUNTY, NORTH DAKOTA

LEGEND	
ARITHMETIC MEAN POROSITY	··········
GEOMETRIC MEAN PERMEABILITY	··········
MEDIAN VALUE	— — —
CUMULATIVE FREQUENCY	———
CUMULATIVE CAPACITY LOST	—·—·—

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CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

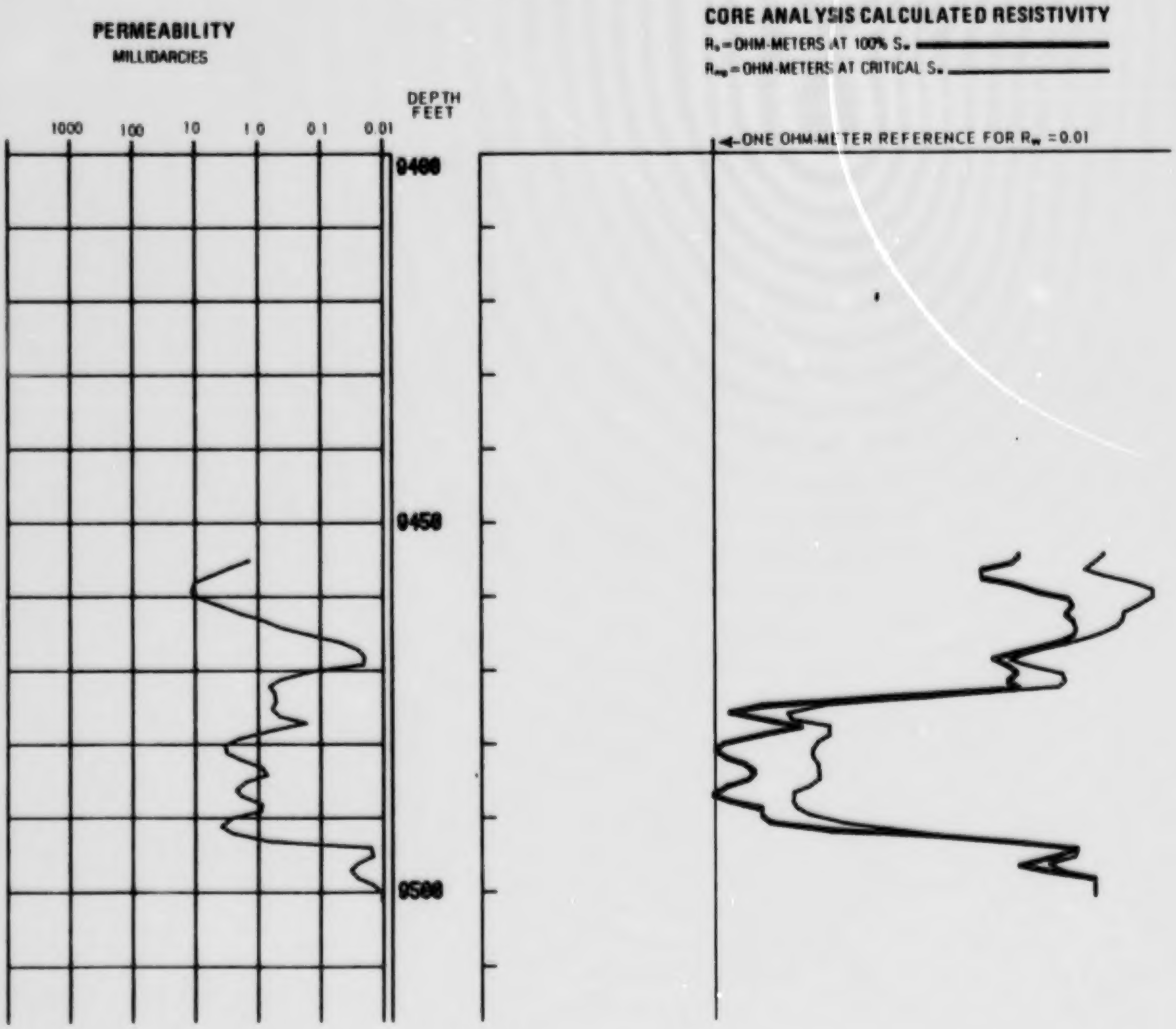
COMPANY	SUN EXPLORATION & PRODUCTION CO.			FILE NO.	3805-3365
WELL	NO. 1 R.G. HICKS	DATE	1-16-84	ENGRS.	R.E.B.
FIELD	EIK FIELD	FORMATION	MISSION CANYON	ELEV.	2244 KB
COUNTY	MCKENZIE STATE NO. DAK.	DRLG. FLD.	SALT SAT NO OIL	CORES	

CoRes Log

CORE and RESISTIVITY EVALUATION

[illegible]

RESISTIVITY PARAMETERS: a = 1.0 m = 2.0 n = 2.0 . Depths 9455.0 to 9502.0 .
a = ________ m = ________ n = ________ . Depths ________ to ________ .



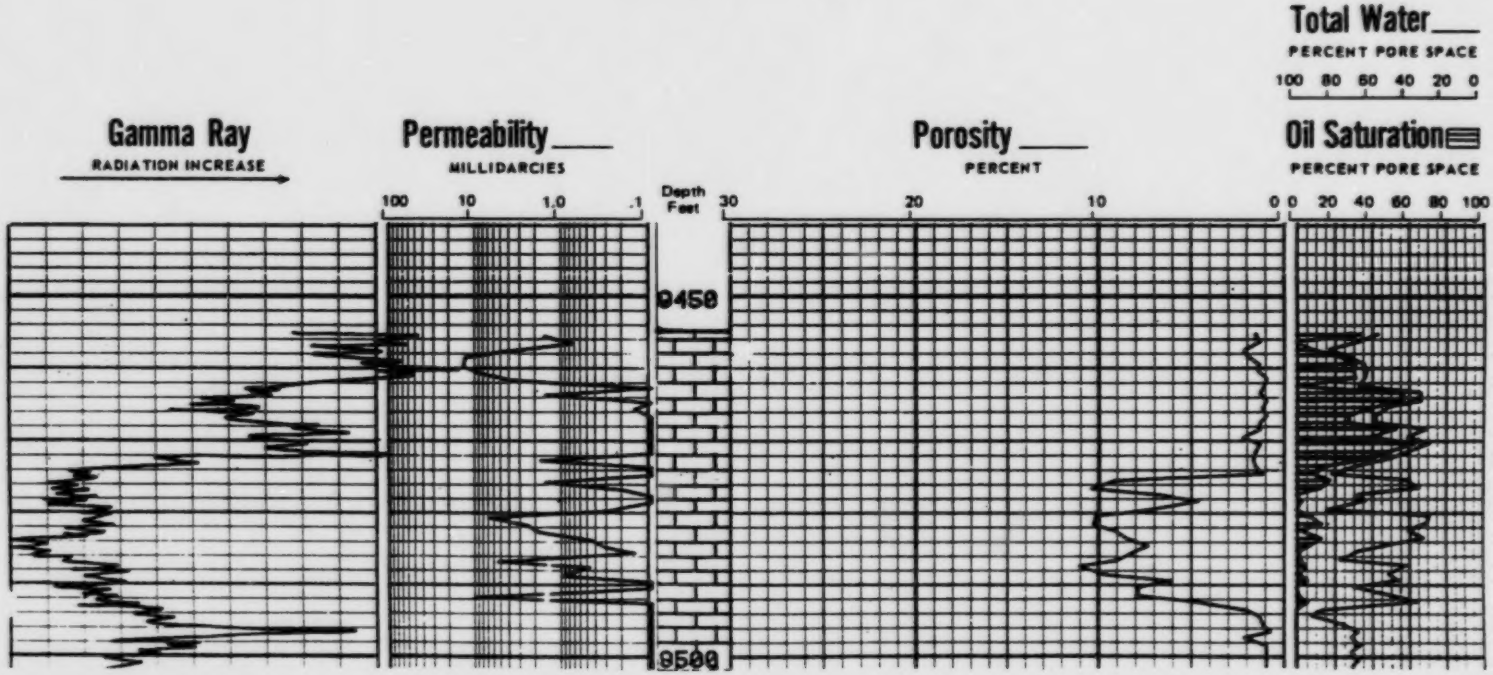
CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

COMPANY SUN EXPLOR. & PROD. CO. FILE NO. 3805-3385
WELL NO. 1 R. G. HICKS DATE 1-10-84
FIELD ELK FORMATION MISSION CANYON ELEV. 2244 KB
COUNTY MCKENZIE STATE NO. DAK. DRLG. FLD. SALT SAT NO OIL CORES
LOCATION NE SW SEC8 T151N R102W

CORRELATION COREGRAPH

These analyses, opinions or interpretations are based on observations and material supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc., (all errors or omissions excepted); but Core Laboratories, Inc., and its officers and employees, assume no responsibility and make no warranty or representations as to the productivity, proper operation, or profitableness of any oil, gas or other mineral well or sand in connection with which such report is used or relied upon.

VERTICAL SCALE: 5" = 100'



Oil and Gas Division

CD-33

WELL COMPLETION REPORT

SEE INSTRUCTIONS OTHER SIDE

OPERATOR Chandler & Associates, Inc. FIELD North Haas
STREET 1401 Denver Club Bldg. POOL Madison
CITY Denver STATE Colo. COUNTY Bottineau
LEASE NAME Anderson WELL NO. 2 ACRES IN UNIT 160
LOCATION SE NW SEC. 20 TWP. 163N RGE. 82W ELEVATION 1551' (XXXXX KB)
¼ of ¼ Section
PERMIT NO. 4104 ELECTRIC OR OTHER LOGS RUN? I-ES and GR-Sonic Neutron & Density logs 19 66
NUMBER OF CRUDE OIL PRODUCING WELLS ON THIS LEASE, INCLUDING THIS WELL -

DATA ON TEST

DATE TEST COMMENCED 7-13 19 66 HOUR 7a.M. DATE TEST COMPLETED 7-14 19 66 HOUR 7 a.M.
LENGTH OF TEST 24 HOURS -0- MINUTES

FOR FLOWING WELL:	FOR PUMPING WELL:
FLOWING PRESSURE ON CSG. ______ LBS./SQ. IN.	LENGTH OF STROKE 64 INCHES
FLOWING PRESSURE ON TBG. ______ LBS./SQ. IN.	NUMBER OF STROKES PER MINUTE 11
SIZE TBG. ______ IN.	WORKING BARRELS 1¼ (SIZE IN.)
SIZE CHOKE ______ IN. TYPE CHOKE ______ (POS. ADJ.)	
SHUT IN PRESSURE ______	SIZE TBG. 2 IN. NO. FT. RUN 3877'

WAS THIS WELL FLOWED FOR THE ENTIRE DURATION OF THIS TEST WITHOUT THE USE OF SWAB OR OTHER ARTIFICIAL DEVICE? --

RESULT OF THIS TEST (BBLS. NET OIL PER 24 HRS.) 90
GAS-OIL RATIO OF THIS WELL IS Est. 190 (CU. FT. OF GAS PER BBL. OF OIL)
PERCENT WATER PRODUCED DURING THIS TEST 1%
GRAVITY OF OIL PRODUCED DURING THIS TEST (CORRECTED TO 60° A.P.I.) 37°

NAME OF PIPE LINE OR OTHER CARRIER Portal Pipeline Company
IF SHOT: DATE ______ NO. QTS. USED ______
IF PERFORATED: NO. HOLES PER FT. 4 IF ACIDIZED: NO. GALS. USED 500
GEOLOGICAL FORMATION SHOT, PERFORATED OR TREATED Kisbey FROM 3865 FT. TO 3868 FT.
SHOOTING, PERFORATING OR TREATING COMPANY Lane Wells and Dowell
DATE WELL COMPLETED 7-6 19 66 HOUR WELL COMPLETED 2 p. M.
TOP OF PAY 3864' FT.

TOTAL DEPTH OF WELL 3945 FT.
PLUG BACK DEPTH 3888 FT.

WAS THIS WELL CORED? Yes WHAT INTERVALS? 3855'-3875'
GIVE DRILL STEM TEST DATA ON REVERSE SIDE OF THIS FORM.

CASING RECORD

Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement	Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement
8 5/8	251.83'		same		175						
4 1/2	3944.		same		200						

EXECUTED THIS 15th DAY OF July 19 66

Chandler & Associates, Inc.
(Company or Operator)

Richard Veghte (Signature) Petroleum Engineer (Title)

STATE OF COLORADO
COUNTY OF DENVER } ss

Before me the undersigned authority, on this day personally appeared Richard Veghte known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states that he is authorized to make this report and has knowledge of the facts stated herein and that said report is true and correct.

Subscribed and sworn to before me this the 15th day of July 19 66

Jacqueline Fell
Jacqueline Fell

My Commission expires May 27, 1969 Notary Public in and for County of Denver State of Colorado

CD-34

SCHLUMBERGER INDUCTION-ELECTRICAL LO

COUNTY BOTTINEAU, N. DAK
FIELD or LOCATION NORTH HAAS
WELL ANDERSON #2
COMPANY CHANDLER & ASSOC.

COMPANY CHANDLER & ASSOCIATES 4092

WELL ANDERSON #2

FIELD NORTH HAAS

COUNTY BOTTINEAU STATE NORTH DAKOTA

LOCATION SE/NW

Sec. 20 Twp. ~~165N~~ 163 Rge. 82W

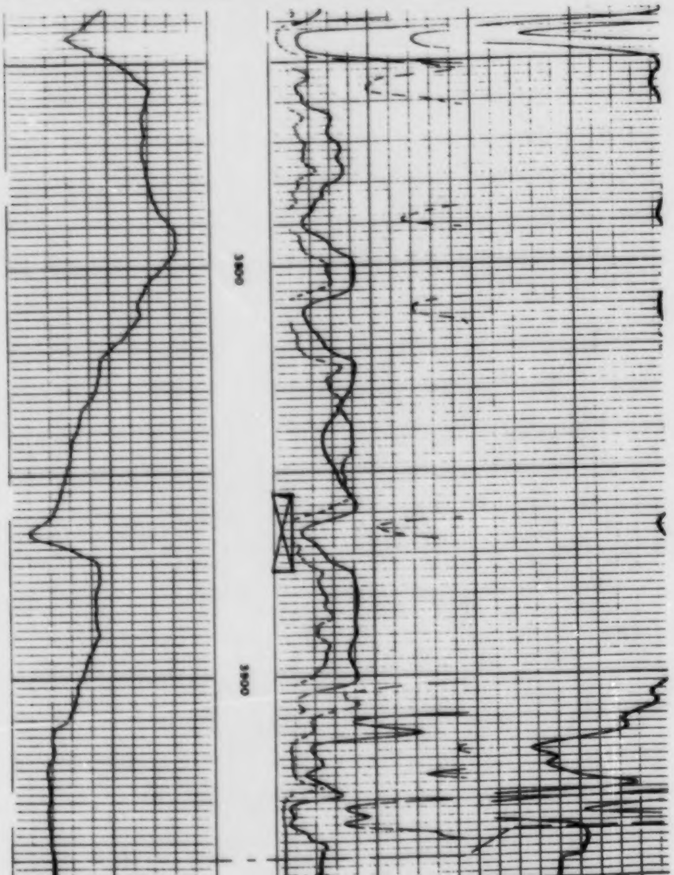
Other Services:
SGR
SNP
FDC

Permanent Datum: GL , Elev. 1544
Log Measured From KB , 7 Ft. Above Perm. Datum
Drilling Measured From KB

Elev.: K.B. 1551
D.F.
G.L. 1544

RDC

Date	6-22-66			
Run No.	ONE			
Depth—Driller	3945			
Depth—Logger	3945			
Btm. Log Interval	3944			
Top Log Interval	253			
Casing—Driller	8-5/8 @ 280	@	@	@
Casing—Logger	253			
Bit Size	7-7/8"			
Type Fluid in Hole	GYP/OIL EMULSION			
Dens. | Visc.	10.2 58			
pH | Fluid Loss	--- -- ml	ml	ml	
Source of Sample	TANK			
R_m @ Meas. Temp.	0.71 @ 83 °F	@ °F	@ °F	@
R_{mf} @ Meas. Temp.	0.46 @ 83 °F	@ °F	@ °F	@
R_{mc} @ Meas. Temp.	---- @ -- °F	@ °F	@ °F	@
Source: R_{mf} R_{mc}	M C			
R_m @ BHT	0.57 @ 108 °F	@ °F	@ °F	@
Time Since Circ.	3 HOURS			
Max. Rec. Temp.	108 °F	°F	°F	
Equip. | Location	4553 WLSTN			
Recorded By	SCHROEDER			
Witnessed By	MR. PABST			



SCHLUMBERGER

FORMATION DENSITY LO

Gamma Gamma

COUNTY BOTTINEAU, N.D.
FIELD or LOCATION NORTH HAAS
WELL ANDERSON # 2
COMPANY CHANDLER & ASSOC.

COMPANY CHANDLER & ASSOCIATES 4092

WELL ANDERSON # 2

FIELD NORTH HAAS

COUNTY BOTTINEAU STATE NORTH DAKOTA

Location: SE/NW

Sec. 20 Twp. 163N Rge. 82W

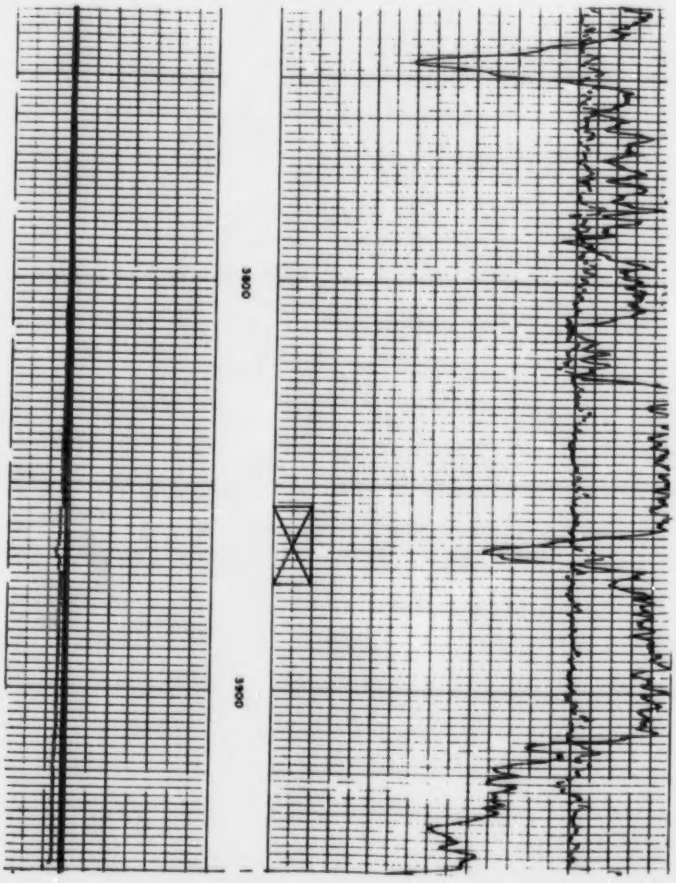
Other Services
IES
SGR
SNP

Permanent Datum: GL ; Elev.: 1544
Log Measured From KB , 7 Ft. Above Perm. Datum
Drilling Measured From KB

Elev.: K.B. 15
D.F. ---
RDC G.L. 15

Date	6-22-66		
Run No.	ONE		
Type Log	FDC		
Depth—Driller	3945		
Depth—Logger	3945		
Bottom logged interval	3944		
Top logged interval	3600		
Type fluid in hole	GYP/OIL EMULSION		
Salinity, PPM Cl.	--		
Density	10.8		
Level	FULL		
Max rec. temp., deg F.	106		
Operating rig time	2 HOURS		
Recorded by	SCHROEDER		
Witnessed by	MR. PABST		

RUN	BORE-HOLE RECORD			CASING RECORD			
No.	Bit	From	To	Size	Wgt.	From	To
ONE	7-7/8	CSG	TD	8-5/8	--	SURF	255



CD-36

4092

CORE LABORATORIES, INC
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page No

CORE ANALYSIS RESULTS

Company	CHANDLER & ASSOCIATES, INC.		KISBY	File	RP-7-139(
Well	NO. 2 ANDERSON		DIA. CONV.	Date Report	6-21-66
Field	UNKNOWN	Drlg. Fl.	GYP BASE-2% DIESEL		BERNDT
County	BOTTINEAU		N.D.	1551 KB	SE NW Sec. 20 T163N R82W

Lithological Abbreviations

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY HORI. K_L	VERT.	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
1	3863-64	74.	0.01	8.2	19.5	17.1	Sd gry fn-med anhy
2	3864-65	256.	0.03	23.0	17.4	39.1	Sd gry fn-med
3	3865-66	8.1	0.04	15.3	22.8	31.4	Sd gry fn anhy

SERVICE NO. 8.

[illegible]

FORM 6

North Dakota State Industrial Commission
Oil and Gas Division

CD-37

WELL COMPLETION REPORT

SEE INSTRUCTIONS OTHER SIDE

OPERATOR Union Oil Company of California FIELD Haas
STREET P. O. Box 2620 POOL Glenburn, Arm of Mission Canyon
CITY Casper STATE WY 82602 COUNTY Bottineau
LEASE NAME A. C. Nelson WELL NO 3-023 ACRES IN UNIT N.A.
LOCATION SW SE (15) SEC 23 TWP 163N RGE 83W ELEVATION 1586' (DF. ~~or KB~~)
¼ of ¼ Section
PERMIT NO 6981 ELECTRIC OR OTHER LOGS RUN? Cased Hole, CNL w/GR 7-27 19 79
NUMBER OF CRUDE OIL PRODUCING WELLS ON THIS LEASE, INCLUDING THIS WELL 3

DATA ON TEST

DATE TEST COMMENCED 8-30 1979 HOUR 7 AM DATE TEST COMPLETED 8-31 1979 HOUR 7 AM
LENGTH OF TEST 24 HOURS - - - MINUTES

FOR FLOWING WELL:
FLOWING PRESSURE ON CSG - - - LBS/SQ IN
FLOWING PRESSURE ON TBG - - - LBS/SQ IN
SIZE TBG - - - - IN
SIZE CHOKE - - IN TYPE CHOKE - - (POS.ADJ.)
SHUT IN PRESSURE - - -

FOR PUMPING WELL:
LENGTH OF STROKE 86 INCHES
NUMBER OF STROKES PER MINUTE 14
WORKING BARRELS 1-1/2 (SIZE IN)
SIZE TBG 2-7/8 IN NO FT RUN 3966'

WAS THIS WELL FLOWED FOR THE ENTIRE DURATION OF THIS TEST WITHOUT THE USE OF SWAB OR OTHER ARTIFICIAL DEVICE? - - -

RESULT OF THIS TEST (BBLS. NET OIL PER 24 HRS.) 169 BO
GAS-OIL RATIO OF THIS WELL IS Not Calculated (CU. FT. OF GAS PER BBL. OF OIL)
PERCENT WATER PRODUCED DURING THIS TEST 40%
GRAVITY OF OIL PRODUCED DURING THIS TEST (CORRECTED TO 60° A.P.I.) 28.6°

NAME OF PIPE LINE OR OTHER CARRIER Koch Pipeline
IF SHOT: DATE - - - NO. QTS. USED - - -
IF PERFORATED: NO. HOLES PER FT 2 spf IF ACIDIZED: NO. GALS. USED 2750 gals.
GEOLOGICAL FORMATION SHOT, PERFORATED OR TREATED Mission Canyon FROM 3963 FT TO 4014 FT
SHOOTING, PERFORATING OR TREATING COMPANY Oilwell Perforators
DATE WELL COMPLETED August 20 19 79 HOUR WELL COMPLETED 6:00 P.M.
TOP OF PAY 3962 FT.

TOTAL DEPTH OF WELL 4095 FT.
PLUG BACK DEPTH 4028 FT.

WAS THIS WELL CORED? Yes WHAT INTERVALS? 3975-4035' (Glenburn-Member of Mission Canyon)
GIVE DRILL STEM TEST DATA ON REVERSE SIDE OF THIS FORM -No DST's

CASING RECORD

Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement	Size	Put in Well Ft.	Put in Well In.	Left in Well Ft.	Left in Well In.	No. Sacks Cement
8-5/8"	371.00'		371.00'		200 sx						
5-1/2"	4,093.00'		4,093.00'		500 sx						

EXECUTED THIS 11th DAY OF September 19 79 Union Oil Company of California
(Company or Operator)

STATE OF WYOMING
COUNTY OF NATRONA } ss

RG Ladd Jr
(Signature)

District Drlg. Supt.
(Title)

Before me the undersigned authority, on this day personally appeared R. G. Ladd, Jr. known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states that he is authorized to make this report and has knowledge of the facts stated herein and that said report is true and correct.

Subscribed and sworn to before me this the 11th day of September, 19 79

Wayne W. Strong

My Commission expires February 13, 1983 Notary Public in and for Natrona County, Wyoming

WAYNE W. STRONG -- Notary Public
County of Natrona State of Wyoming
My Commission Expires Feb. 13, 1983

CD-38

Schlumberger PERFORATING DEPTH CONTR

COUNTY BOTTINEAU
FIELD or LOCATION HAAS SEC. 23-163N-83W
WELL NELSON NO. 3-023
COMPANY UNION OIL CO. OF CALIF.

COMPANY UNION OIL COMPANY OF CALIFORNIA
WELL NELSON NO. 3-023
FIELD HAAS
COUNTY BOTTINEAU STATE NORTH DAKOTA

#6951

Location Sw SE
660' FSL 1980' FEL SW SE
Sec. 23 Twp. 163N Rge. 83W

Other Servic
NONE

Permanent Datum: GL ; Elev.: 1579
Log Measured From KB , 9 Ft. Above Perm. Datum
Drilling Measured From KB

Elev.: K.B.
D.F.
G.L.

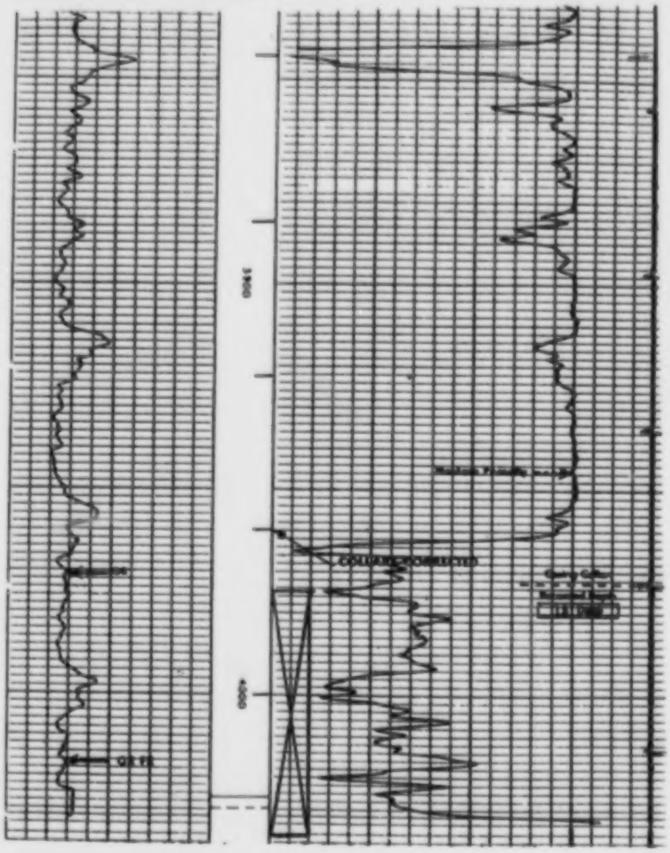
Date	7/27/79		
Run No.	ONE		
Type Log	CNL/GR		
Depth – Driller	4040		
Depth – Logger	4028		
Bottom logged interval	4025		
Top logged interval	3500		
Type fluid in hole	SALT WATER		
Salinity, PPM Cl.	---		
Density	9		
Level	FULL		
Max. rec. temp., deg F.	110		
Operating rig time	2 HOURS		
Recorded By	J. STEDMAN		
Witnessed By	R. SCHUYLER		

BORE-HOLE RECORD

Bit Size	From	To
10-3/4	SURF	
7-7/8		TD

CASING RECORD

Size	Wgt.	From	T
8-5/8		SURF	
4-1/2		SURF	TD



Schlumberger PERFORATING DEPTH CONTR

COUNTY BOTTINEAU
FIELD or LOCATION HAAS SEC. 23-163N-83W
WELL NELSON NO. 3-023
COMPANY UNION OIL CO. OF CALIF.

COMPANY UNION OIL COMPANY OF CALIFORNIA

WELL NELSON NO. 3-023

#6951

FIELD HAAS

COUNTY BOTTINEAU STATE NORTH DAKOTA

Location SW SE
660' FSL 1980' FEL SW SE

Sec. 23 Twp. 163N Rge. 83W

Other Servic
NONE

Permanent Datum: GL ; Elev.: 1579
Log Measured From KB , 9 Ft. Above Perm. Datum
Drilling Measured From KB

Elev.: K.B.
D.F.
G.L.

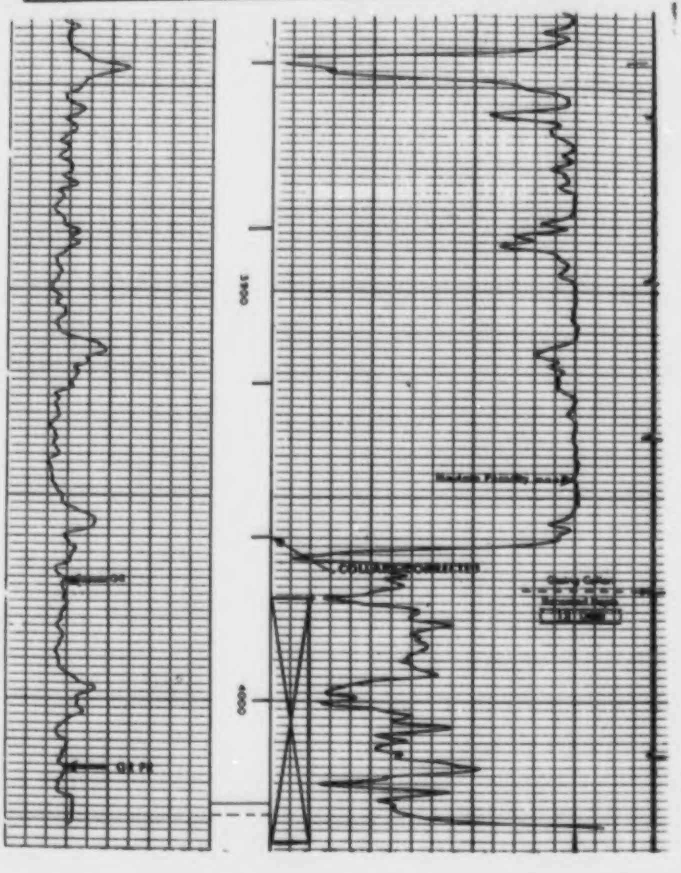
Date	7/27/79		
Run No.	ONE		
Type Log	CNL/GR		
Depth — Driller	4040		
Depth — Logger	4028		
Bottom logged interval	4025		
Top logged interval	3500		
Type fluid in hole	SALT WATER		
Salinity, PPM Cl.	---		
Density	9		
Level	FULL		
Max. rec. temp., deg F.	110		
Operating rig time	2 HOURS		
Recorded By	J. STEDMAN		
Witnessed By	R. SCHUYLER		

BORE-HOLE RECORD

Bit Size	From	To
10-3/4	SURF	
7-7/8		TD

CASING RECORD

Size	Wgt.	From	T
8-5/8		SURF	
4-1/2		SURF	TD



CD-40

1981

CORE ANALYSIS RESULTS FOR
UNION OIL COMPANY OF CALIFORNIA

A.C. NELSON 3-0-23

HAAS FIELD

BOTTINEAU COUNTY, NORTH DAKOTA

CD-41

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

UNION OIL CO. OF CALIFORNIA
A.C. NELSON 3-0-23
HAAS FIELD
BOTTINEAU COUNTY

FORMATION : GLENBURN
DRLG. FLUID: SALT GEL - NO OIL
LOCATION : SW SE SEC. 23-T163N-R83W
STATE : NORTH DAKOTA

DATE : 7-25-79
FILE NO. : 9105-2525
ANALYSTS : REB
ELEVATION: 1588' KB

CONVENTIONAL CORE ANALYSIS

SAMP. NO.	DEPTH	PERM. TO AIR (MD) HORZ.	PERM. TO AIR (MD) VERTICAL	POR. FLD.	FLUID SATS. OIL	FLUID SATS. WATER	GR. DNS.		DESCRIPTION
1	3975-76	54		17.1	32.1	34.4			LM, FN XLN ANHY
2	3976-77	10		8.7	16.9	53.1		VF	LM, ALGAL OOL
3	3977-78	47		11.2	26.4	35.1			LM, FN XLN-ALGAL
4	3978-79	25		15.6	18.6	45.9			LM, ALGAL PISO
5	3979-80	38		17.0	17.7	41.0			LM, FN XLN-ALGAL
6	3980-81	69		13.9	17.3	38.8			LM, FN XLN-ALGAL PISO
7	3981-82	11		20.3	19.1	40.9			LM, FN XLN-ALGAL
8	3982-83	36		14.3	18.9	43.1			LM, ALGAL PISO
9	3983-84	100		16.5	17.5	55.9			LM, FN XLN-ALGAL
10	3984-85	38		25.1	21.7	54.6			LM, FN XLN-ALGAL DOL
11	3985-86	3.5		21.9	19.1	44.7			LM, FN XLN ARGIL
12	3986-87	0.36		13.2	0.0	96.5			DOL, V/FN XLN
13	3987-88	0.44		15.2	4.7	84.0		VF	DOL, V/FN XLN
14	3988-89	17		22.2	14.8	44.5			LM, ALGAL PISO
15	3989-90	27		23.1	26.2	28.6			LM, FN XLN-ALGAL PISO
16	3990-91	7.2		11.5	13.7	46.4			LM, FN XLN-ALGAL PISO
17	3991-92	0.47		9.0	14.7	61.4			LM, FN XLN V/ANHY
18	3992-93	6.6		14.6	19.5	38.9			LM, ALGAL PISO
19	3993-94	1.3		17.0	20.3	45.2		VF	LM, FN XLN-ALGAL
20	3994-95	9.1		14.2	14.2	47.3			LM, ALGAL PISO
21	3995-96	9.4		12.3	16.5	33.1			LM, ALGAL PISO-PELLET
22	3996-97	11		12.7	13.8	44.5			LM, ALGAL PISO-PELLET
23	3997-98	2.3		15.7	22.8	31.1			LM, FN XLN-ALGAL PISO
24	3998-99	102		15.3	19.9	43.4			LM, ALGAL OOL-PISO
25	3999 -0	54		15.9	16.6	52.1			LM, ALGAL OOL-PISO

VF = VERTICAL FRACTURE

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CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

UNION OIL CO. OF CALIFORNIA
A.C. NELSON 3-0-23
HAAS FIELD
BOTTINEAU COUNTY

FORMATION : GLENBURN
DRLG. FLUID: SALT GEL - NO OIL
LOCATION : SW SE SEC. 23-T163N-R83W
STATE : NORTH DAKOTA

DATE : 7-25-79
FILE NO. : 9105-2525
ANALYSTS : REB
ELEVATION: 1588' KB

CONVENTIONAL CORE ANALYSIS

SAMP. NO.	DEPTH	PERM. TO AIR (MD) HORZ.	PERM. TO AIR (MD) VERTICAL	POR. FLD.	FLUID SATS. OIL	FLUID SATS. WATER	GR. DNS.		DESCRIPTION
26	4000 -1	35		14.1	17.0	49.0			LM, ALGAL PISO-PELLET
27	4001 -2	32		16.2	18.7	49.0			LM, FN XLN-ALGAL
28	4002 -3	14		17.8	19.0	51.8			LM, FN XLN-ALGAL
29	4003 -4	191		11.6	13.5	50.7			LM, FN XLN-ALGAL PELLET
30	4004 -5	6.5		17.3	19.5	49.8			LM, FN XLN-ALGAL PISO
31	4005 -6	103		15.4	18.6	37.5			LM, FN XLN-ALGAL PISO
32	4006 -7	33		23.2	17.5	53.3			LM, FN XLN-ALGAL PISO
33	4007 -8	36		19.4	13.6	61.3			LM, FN XLN-ALGAL
34	4008 -9	25		19.8	12.0	55.9			LM, FN XLN DOL
35	4009-10	46		26.0	13.2	59.1			LM, FN XLN-ALGAL PISO
36	4010-11	17		29.5	15.8	41.7		VF	LM, FN XLN-ALGAL PISO
37	4011-12	0.94		15.3	4.5	62.2		VF	DOL, V/FN XLN
38	4012-13	0.76		17.1	1.2	88.3			DOL, V/FN XLN
39	4013-14	16		15.3	17.5	36.3			LM, FN XLN-ALGAL
40	4014-15	5.6		17.0	6.0	67.0			DOL, V/FN XLN
41	4015-16	6.9		10.9	14.5	49.0		VF	LM, ALGAL OOL-PISO
42	4016-17	5.6		14.2	10.7	42.8		VF	LM, ALGAL OOL-PISO
43	4017-18	12		20.2	13.8	51.6		VF	LM, FN XLN-ALGAL
44	4018-19	12		19.3	15.3	46.7			LM, FN XLN-ALGAL
45	4019-20	1.5		11.4	10.3	53.3			LM, FN XLN-ALGAL PISO
46	4020-21	5.4		17.5	8.7	74.5			LM, FN XLN-ALGAL
47	4021-22	37		24.5	13.2	48.2			LM, ALGAL OOL
48	4022-23	9.5		13.6	11.3	49.5			LM, ALGAL PISO
49	4023-24	29		21.2	11.0	65.9			LM, ALGAL OOL
50	4024-25	0.53		10.1	0.0	94.5			DOL, V/FN XLN

VF = VERTICAL FRACTURE

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CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

UNION OIL CO. OF CALIFORNIA
A.C. NELSON 3-0-23
HAAS FIELD
BOTTINEAU COUNTY

FORMATION : GLENBURN
DRLG. FLUID: SALT GEL - NO OIL
LOCATION : SW SE SEC. 23-T163N-R83W
STATE : NORTH DAKOTA

DATE : 7-25-79
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ELEVATION: 1588' KB

CONVENTIONAL CORE ANALYSIS

SAMP. NO.	DEPTH	PERM. TO AIR (MD) HORZ.	PERM. TO AIR (MD) VERTICAL	POR. FLD.	FLUID SATS. OIL	FLUID SATS. WATER	GR. DNS.		DESCRIPTION
51	4025-26	3.4		13.2	6.5	38.7			LM, FN XLN-ALGAL PISO
52	4026-27	1.1		7.7	9.2	71.2		VF	LM, FN XLN-ALGAL
53	4027-28	6.5		13.0	5.3	85.6		VF	LM, FN XLN-ALGAL
54	4028-29	21		13.6	10.2	70.2		VF	LM, FN XLN-ALGAL
55	4029-30	7.0		18.9	4.6	81.1		VF	LM, FN XLN-ALGAL PISO
56	4030-31	28		23.4	14.5	61.1			LM, FN XLN-ALGAL
57	4031-32	14		11.3	7.8	38.1			LM, FN XLN-ALGAL PISO
58	4032-33	1.9		13.3	11.7	46.8			LM, ALGAL OOL
59	4033-34	4.7		15.3	10.7	38.2			LM, ALGAL OOL ARGIL
60	4034-35	4.4		18.3	1.0	61.3			LM, SDY CLY

VF = VERTICAL FRACTURE

These analyses, opinions or interpretations are based on observations and materials supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted); but Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or

CD-44

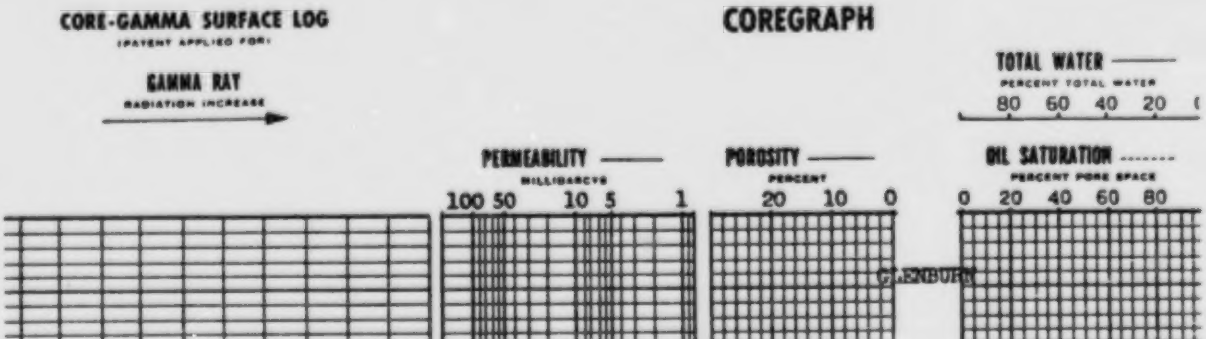
CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

OMPANY UNION OIL CO. OF CALIFORNIA FIELD HAAS FILE 9105-2525
/ELL A.C. NELSON 3-0-23 COUNTY BOTTINEAU DATE 7-25-79
OCATION SW SE SEC. 23-T163N-R83W STATE NORTH DAKOTA ELEV. 1588' KB

CORE-GAMMA CORRELATION

[illegible]

VERTICAL SCALE: 5" = 100'



CORE SUMMARY AND CALCULATED RECOVERABLE OIL

FORMATION NAME AND DEPTH INTERVAL: GLENBURN - 3975.0-4024.0 Feet

FEET OF CORE RECOVERED FROM ABOVE INTERVAL	49	AVERAGE TOTAL WATER SATURATION: PER CENT OF PORE SPACE	47.4
FEET OF CORE INCLUDED IN AVERAGES	44	AVERAGE CONNATE WATER SATURATION: PER CENT OF PORE SPACE	45 (e)
AVERAGE PERMEABILITY: MILLIDARCYS	30.6	OIL GRAVITY: °API	29 (e)
PRODUCTIVE CAPACITY: MILLIDARCY-FEET	1345.4	ORIGINAL SOLUTION GAS-OIL RATIO: CUBIC FEET PER BARREL	
AVERAGE POROSITY: PER CENT	17.1	ORIGINAL FORMATION VOLUME FACTOR: BARRELS SATURATED OIL PER BARREL STOCK-TANK OIL	1.20(e)
AVERAGE RESIDUAL OIL SATURATION: PER CENT OF PORE SPACE	16.7	CALCULATED ORIGINAL STOCK-TANK OIL IN PLACE: BARRELS PER ACRE-FOOT	608

Calculated maximum solution gas drive recovery is barrels per acre-foot, assuming production could be continued until reservoir pressure declined to zero psig. Calculated maximum water drive recovery is barrels per acre-foot, assuming full maintenance of original reservoir pressure, 100% areal and vertical coverage, and continuation of production to 100% water cut. *(Please refer to footnotes for further discussion of recovery estimates.)*

(c) Calculated (e) Estimated (m) Measured (*) Refer to attached letter.

INTERPRETATION OF DATA

3975.0-4024.0 Feet - Believed to be oil productive.
4024.0-4035.0 Feet - Transition zone.

These recovery estimates represent theoretical maximum values for solution gas and water drive. They assume that production is started at original reservoir pressure; i.e., no account is taken of production to date or of prior drainage to other areas. The effects of factors tending to reduce actual ultimate recovery, such as economic limits on oil production rates, gas-oil ratios, or water-oil ratios, have not been taken into account. Neither have factors been considered which may result in actual recovery intermediate between solution gas and complete water drive recoveries, such as gas cap expansion, gravity drainage, or partial water drive. Detailed predictions of ultimate oil recovery to specific abandonment conditions may be made in an engineering study in which consideration is given to overall reservoir characteristics and economic factors.

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CD-46

8

Form 6

SFN 2468

NORTH DAKOTA STATE INDUSTRIAL COMMISSION
Oil and Gas Division
900 East Boulevard, Bismarck, ND 58505

APR 1988
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ND OIL & GAS
DIVISION

WELL COMPLETION OR RECOMPLETION REPORT
(Submit in Triplicate)

Designate type of completion: OIL WELL ☒ XX GAS WELL ☐ OTHER ____ SAME RESVR ☐

NEW WELL ☒ XX WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ OTHER ____ DIFF. RESVR ☐

Well File No.: 12356
Date Issued: 2-18-88
Well Name & No.: Nelson #1-13
Spacing (Unit Description): SW/4 SW/4 Sec. 13-159N-82W
OPERATOR: CNG Producing Co.-Tulsa Div.
Field: Elms
ADDRESS: Box 2115, Tulsa, OK 74101-2115
Pool: Madison
LOCATIONS (Show quarter-quarter, footages, and section, township and range.)
At surface: 660' FSL & 660' FWL Sec. 13-159N-82W
Wildcat, Development: Development
At top prod. interval, reported below:
County: Bottineau
At total depth:

Date Spudded	Date TD Reached	Date Comp.(ready to prod)	Elevation (KB,DF,GR)	Total Depth (MD & TVD)	Plug Back (TD,MD,TVD)
3-5-88	3-12-88	4-2-88	1542 GR	4650 MD	4607

PRODUCING INTERVAL(S), THIS COMPLETION, TOP, BOTTOM, NAME (MD & TVD): Wayne Porosity @ 4494-4540 MD
No. of DST's Run (see back): None
Date Directional Survey Submitted: N/A
TYPE ELECTRIC AND OTHER LOGS RUN (See instructions): DLL/MSFL, BCS, CDCNL, WEL
Was Well Cored: Yes

CASING RECORD (Report all strings set in well)

Casing Size	Depth Set (MD)	Hole Size	Weight Lbs./Ft.	Sacks Cement	Amount Pulled
8 5/8"	464'	12 1/4"	23#	230	None
5 1/2"	4650'	7 7/8"	14#	545	None

LINER RECORD

Size	Top (MD)	Bottom (MD)	Sacks Cement	Screen (MD)
None				

TUBING RECORD

Size	Depth Set (MD)	Packer Set (MD)
2 7/8"	4523'	4493'

PERFORATION RECORD

Depth Interval (MD)	Holes per ft.	Size and Type	Purpose
4500-4507	4 SPF	4" csg gun	Production

ACID, SHOT, FRAC., CEMENT SQUEEZE, Etc.

Amt. & Kind of Material Used	Depth Interval (MD)
500 gals 15% HCl	Pre-perf

PRODUCTION

Date First Production	Producing Method (Flowing, gas, lift, pumping - size & type of pump)	Well Status (Prod. or shut-in)
3-20-88	Pumping - 1 3/4" BHD	Producing

Date of Test	Hours Tested	Choke Size	Production For Test	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Oil Gravity - API (Corr.)
4-4-88	24	--		120	TSTM	148	34

Flow, Tubing Press.	Casing Pressure	Calculated 24-Hour Rate	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Gas-Oil Ratio
4-4-88	--		120	TSTM	148	n/a

DISPOSITION OF OIL & GAS (Purchaser and Transporter)
Purchaser: Murphy Oil Co.
Transporter: Murphy Oil U.S.A./Ritts Trucking

Test Witnessed By:

LIST OF ATTACHMENTS
None: Core analysis to be submitted upon completion of same.
Logs submitted directly by logging company.

Over to Complete Form

CD-47

GEOLOGIC MARKERS

Name	Measured Depth of Formation	True Vertical Depth
Greenhorn	2124	
Belle Fourche	2236	
Mowry	2412	
Dakota	2654	
Morrison-Swift	2960	
Piper Limestone	3266	
Spearfish	3748	
Charles	3988	
Lower Berentson	4160	
Midale	4192	
Base State 'A'	4278	
Glenburn	4420	
Wayne	4494	
Mission Canyon-2 Anhyd.	4608	
Tilston	4624	

Drill Stem Test Data : N/A

I hereby swear or affirm that the information herein provided is true, complete and correct as determined from all available records.

Susan Lacy	Engineering Technician	April 13, 1988
Signature	Title	Date

State of Oklahoma)
)ss
County of Tulsa)

On this 13th day of April, 19 88, before me personally appeared Susan Lacy to me known as the person described in and who executed the foregoing instrument and acknowledged that (s)he executed the same as his/her free act and deed.

Notary Seal

Geraldine Knight
Notary Public
State of Oklahoma County of Tulsa
My Commission expires May 22, 1993

INSTRUCTIONS

1. Within thirty (30) days after the completion of a well, or recompletion of a well in a different pool, the original and three copies of this report must be filed with the North Dakota Industrial Commission, Oil and Gas Division.

2. Immediately after the completion or recompletion of a well in a pool or reservoir not then covered by an order of the commission, the original and three copies of this report must be filed with the North Dakota Industrial Commission, Oil and Gas Division.

3. The owner or operator shall file with the Oil and Gas Division three copies of the following: all logs run, drill stem test reports and charts, formation water analysis and noninterpretive lithologic logs or sample descriptions if compiled.

CD-48

GEARHART

MICRO SPHERICALLY FOCUSSED LATEROLOG

FILING NO.
383795

COMPANY CNG PRODUCING CO.
WELL 1-13 MELSON
FIELD WILDCAT
COUNTY BOTTINEAU STATE N. DAKOTA

Location
SW-SW
[illegible] FSL
[illegible] FWL

Other services
CDL-C
[illegible]

Scl.:7618-14-88

Sec 13 Twp 159N Rge 82W

Permanent Datum GL Elev. 1542
Log Measured From KB , 12 Above perm. Datum
Drilling Measured From KB

Elevations
K.B. 155
D.F. 155
G.L. 154.

Date	3-12-88			
Run No	ONE			
Depth-Driller	4658			
Depth-Logger	4646			
Bottom Logged Interval	4644			
Top Logged Interval	468.5			
Casing Size @ Depth	8 5/8 @ 464	@		@
Casing-Logger	464			
Bit Size	7 7/8			
Type Fluid in Hole	SALT MUD			
Density | Viscosity	10.4 | 40			
pH | Fluid Loss	7.0 | 4.0 cc	cc	cc	
Source of Samples	MUDTANK			
Rm @ Meas. Temp.	.096 @ 59.3 °F	@ °F	@ °F	@
Rmf @ Meas. Temp.	.075 @ 52.1 °F	@ °F	@ °F	@
Rmc @ Meas. Temp.	.145 @ 52.1 °F	@ °F	@ °F	@
Source Rmf | Source Rmc	MEAS | CHART			
Rm @ BHT	.057 @ 118 °F	@ °F	@ °F	@
End Circulation Time	1345			
Logger on Bottom Time	1454			
Max. rec temp. deg. F	118 °F	°F	°F	
Equip. No. | Location	7618 | WLSTN	|	|	|
Recorded By	T. SCHMIDT			
Witnessed By	MR. JEFFCOAT-	SNECO		

APR 1988
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N.D. OIL & GAS
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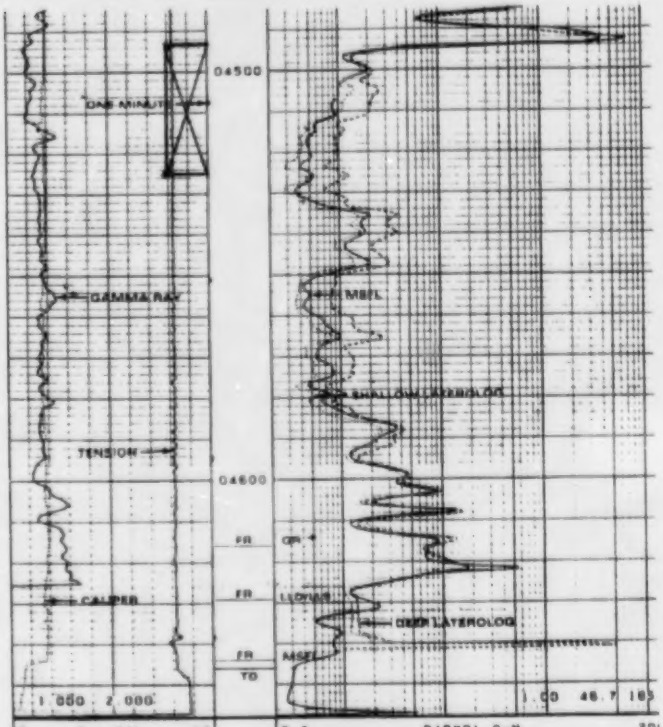

6	X - CAL	16	
0	GR API	100	
10000	TENSION	0	
0.2	R(RXO) Ω-M	20	
0.2	R(LLS) Ω-M	20	
0.2	R(LLD) Ω-M	20	

03-12-88	15:03	4697.5	383795	0008-06	0
03-12-88	14:59	4395.0	383785	0087-25	0

GEARHART

COMPENSATED NEUTRON LOG

FILING NO.
383795

COMPANY CNG PRODUCING CO.
WELL 1-13 NELSON
FIELD WILDCAT
COUNTY BOTTINEAU STATE N. DAKOTA

Location SW/SW [illegible]
Ect.:7610-14-88
Sec 13 Twp 159N Rge 82W

Other services [illegible]

Permanent Datum GL Elev. 1842
Log Measured From KB , 17 Above perm. Datum
Drilling Measured From KB

Elevations
K.B. [illegible]
D.F. 1853
G.L. 1842

Date	3-12-88			
Run No	ONE			
Depth-Driller	4650			
Depth-Logger	4644			
Bottom Logged Interval	4642			
Top Logged Interval	3642.5			
Type Fluid in Hole	SALT MUD			
Density / Viscosity	10.4	40		
pH / Fluid Loss	7.0	4.0	c	
Max. rec temp. deg. F	110 °F		°F	
Source of Samples	MUDTANK			
Rm @ Meas. Temp.	.096 @ 059.3 °F		@ °F	@
Rmf @ Meas. Temp.	.075 @ 052.1 °F		@ °F	@
Rmc @ Meas. Temp.	.145 @ 052.1 °F		@ °F	@
Source Rmf / Source Rmc	MEAS	CHART	|	|
End Circulation Time	1345			
Logger on Bottom Time	1600			
Recorded By	T. SCHMIDT			
Witnessed By	MR. JEFFCOAT-	IACCO		

Bore-Hole Record					Casing Record		
Run no	Level	Bit	From	To	Size	Wgt.	From
ONE	FULL	12.25	SURF	483	8 5/8	--	SURF
TWO	FULL	7.87	483	4650			

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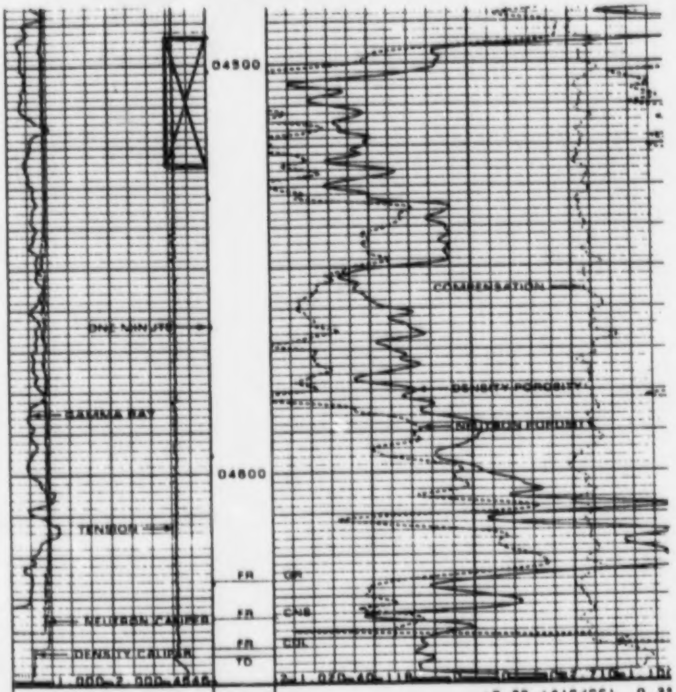

-0.25 ΔP(G/CC) 0.25

0 GR (API) 100	
6 CAL-X (IN) 16	30 Φ-CDL -10
6 CAL-Y (IN) 16	30 Φ-CNS.LM -10
10000 TENSION (LBS) 0	

CD-50

13356

TerraTek

Geoscience Services

JUN 1988
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CONFIDENTIAL C

TerraTek Core Services

Final Report
Routine Core Analysis

CNG PRODUCING COMPANY

Nelson 1-13 Well
Bottineau County, North Dakota

TTCS File No. 88132

Core No.	Interval	Formation
1	4465.0-4525.2	Wayne

University Research Park • 360 Wakara Way • Salt Lake City, Utah 84108, U.S.A. • Telephone (801) 584-2480 • Telex 910-9255284

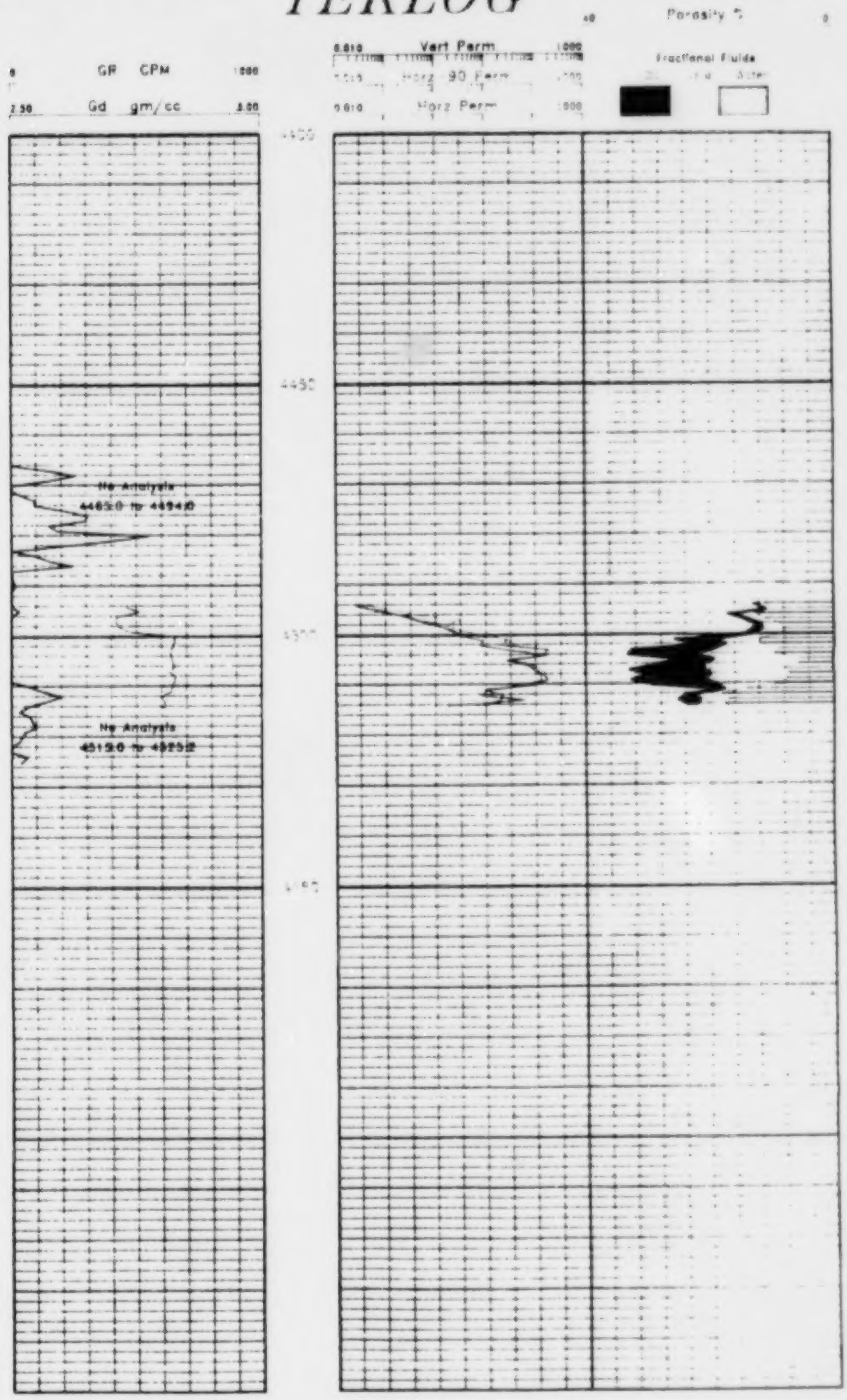
TERRA TEK CORE SERVICES

380 Wakara Way, SLC Utah 84108 (801) 584-2480

CNG PRODUCING COMPANY
Nelson 1-13

TEKLOG

MAY 02, 1988
TTCS# 88132



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University Research Park · 360 Wakara Way · Salt Lake City, Utah 84108 · (801) 584-2480 · TWX 910-925-5284

CNG PRODUCING COMPANY

Well:	Nelson 1-13	State:	North Dakota	Date:	29-APR-1988
Field:	Wildcat	County:	Bottineau	TTCS File #:	88132
Drilling fluid:	Starch salt	Location:	Sec.13-T159N-R82W	Elevation:	1542 GL

FULL DIAMETER DEAN-STARK ANALYSIS

Sample Number	Depth (feet)	Permeability Horz (md)	Horz-90 (md)	Vert (md)	Porosity %	Saturation Oil %	H2O %	Grain Density (gm/cc)		Lithology
	Wayne Formation									
	4465.0-94.0									Dol.NS,anhy; No analysis per client
1	4494.0-95.0	.04	.04	.02	13.0	0.0	87.2	2.73		Ls.fxl,anhy xls
2	4495.0-96.0	.15	.05	.09	11.0	0.0	87.0	2.76	VF	Ls,fxl,anhy
3	4496.0-97.0	.42	.25	.20	17.2	8.5	74.4	2.71		Ls,m-vcg,ool-pis
4	4497.0-98.0	3.0	.52	.40	14.9	6.5	76.2	2.71	VF	Ls,m-vcg,ool-pis,sty
5	4498.0-99.0	1.7	1.6	1.0	12.9	9.3	68.1	2.72	VF	Ls,m-vcg,ool-pis,sty
6	4499.0-00.0	2.7	1.6	2.3	13.3	13.6	63.0	2.73	VF	Ls,f-mg,ool,sty
7	4500.0-01.0	6.8	4.7	2.8	14.8	12.9	55.2	2.83	VF	Dol,fxl,pis,pp vgs
8	4501.0-02.0	32.	27.	8.8	25.9	28.0	46.9	2.83		Dol,fxl,pis,pp vgs
9	4502.0-03.0	23.	18.	7.8	22.5	22.0	53.8	2.82		Dol,fxl,pis,pp vgs
10	4503.0-04.0	177.	171.	30.	32.8	40.8	28.1	2.82		Dol,fxl,few pp vgs,shy lam
11	4504.0-05.0	181.	134.	163.	33.3	32.9	29.3	2.82		Dol,fxl.few pp vgs
12	4505.0-06.0	31.	30.	25.	25.5	24.3	22.0	2.82		Dol,fxl,vgy
13	4506.0-07.0	82.	76.	69.	29.2	28.3	18.6	2.82		Dol,fxl,sl/vgy
14	4507.0-08.0	146.	107.	95.	33.1	37.0	25.2	2.81		Dol,fxl,sl/vgy
15	4508.0-09.0	152.	142.	126.	30.5	34.9	23.6	2.83		Dol.fxl,pp vgs
16	4509.0-10.0	171.	169.	130.	32.8	35.9	23.9	2.82		Dol.fxl,pp vgs
17	4510.0-11.0	103.	94.	57.	29.6	36.8	28.1	2.82		Dol.fxl,pp vgs
18	4511.0-12.0	9.6	6.3	9.7	19.4	8.9	74.6	2.82	VF	Dol,fxl,pp vgs

VF - Vertical fracture present

CNG PRODUCING COMPANY
Well: Nelson 1-13

Date: 29-APR-1988

TTCS File #: 88132

FULL DIAMETER DEAN-STARK ANALYSIS

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90 (md)	Permeability Vert (md)	Porosity %	Saturation Oil %	Saturation H2O %	Grain Density (gm/cc)		Lithology
19	4512.0-13.0	8.2	7.4	22.	24.0	7.0	76.2	2.80		Dol,fxl,pp vgs
20	4513.0-14.0	60.	51.	18.	25.3	14.7	67.7	2.81	VF	Dol,fxl,pp vgs
21	4514.0-15.0	6.5	1.8	9.3	23.6	6.0	73.7	2.80		Dol,fxl,pp vgs
	4515.0-25.2									Dol,NS,anhy; No analysis per client

VF - Vertical fracture present

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HORIZONTAL PERMEABILITY
VS
POROSITY

CNG Producing Company
Nelson 1–13
Wildcat
Bottineau County, ND
MAY 02, 1988

Depth interval: 4494.0 to 4515.0 feet
TTCS# 88132

Porosity (phi),

Min	Max	Average
11.010	33.338	23.086

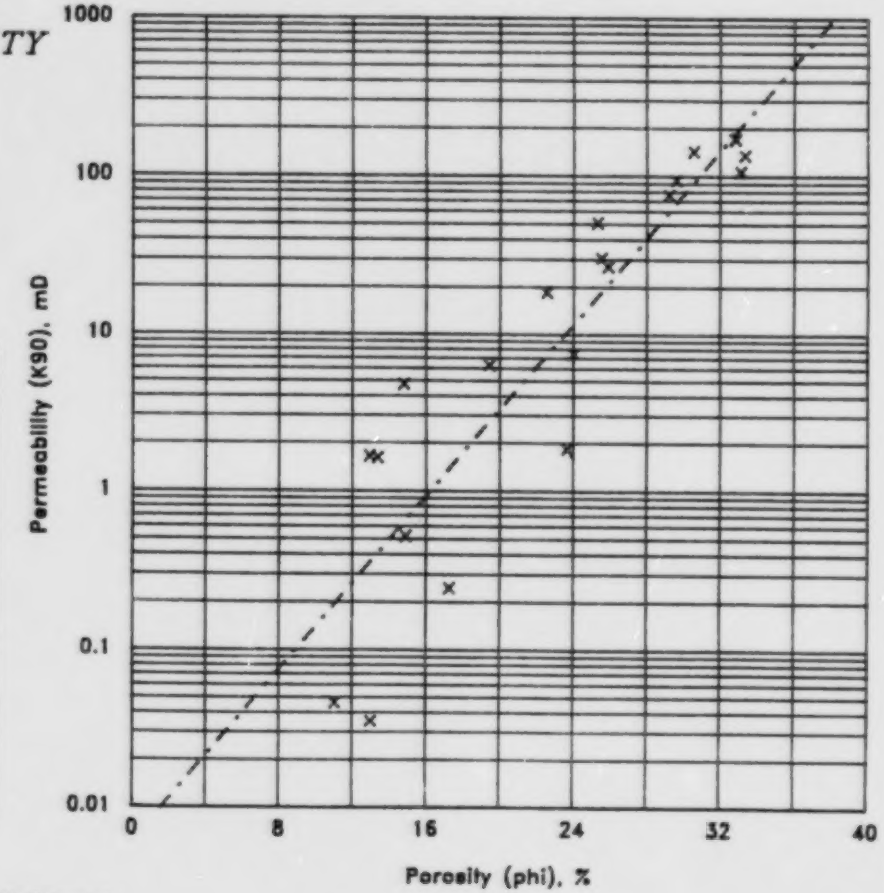
Permeability (K90), mD

Min	Max	Geo. Ave
0.035	171.455	8.803

Equation of the Line

log K90 = α phi + β
log K90 = 0.1368 phi −2.2135
Correlation Coefficient : 0.904

Wayne Formation



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BM.

Form 6
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SFN 2468

NORTH DAKOTA STATE INDUSTRIAL COMMISSION
Oil and Gas Division
~~900~~ 600 East Boulevard, Bismarck, ND 58505

NOV 1990
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WELL COMPLETION OR RECOMPLETION REPORT
(Submit in Triplicate)

Well File No. 12886

Date Issued 3-28-90

Well Name & No. CONNELL 24-27

Spacing (Unit Description) SEC. 27, T144N-R102W
REF: ORDER NO. 5774

Designate type of completion: OIL WELL ☒ GAS WELL ☐ OTHER ______ SAME RESVR ☒

NEW WELL ☒ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ OTHER ______ DIFF. RESVR ☐

OPERATOR: SHELL WESTERN E&P INC.

Field: BUCKHORN

ADDRESS: P.O. BOX 576, HOUSTON, TEXAS 77001 (WCK 4435)

Pool: BUCKHORN-BAKKEN

LOCATIONS (Show quarter-quarter, footages, and section, township and range.)
At surface: 750' FSL & 1660' FWL (SE SW)
At top prod. interval, reported below: 1308' FSL & 1661' FWL (SE SW)
At total depth: 919' FNL & 898' FWL (NW NW)
SEC. 27, T144N-R102W

Wildcat, Development: DEVELOPMENT

County: BILLINGS

Date Spudded	Date TD Reached	Date Comp. (ready to prod.)	Elevation (KB,DF,GR)	Total Depth (MD & TVD)	Plug Back (TD,MD,TVD)
6-07-90	9-25-90	11-08-90	2345' GR	13,958' (MD) 10,530' (TVD)	----

PRODUCING INTERVAL(S), THIS COMPLETION, TOP, BOTTOM, NAME (MD & TVD)
10,513' - 10,530' (TVD) -- LOWER LODGEPOLE, BAKKEN
10,829' - 13,954' (MD)

No. of DST's Run (see back): 1

Date Directional Survey Submitted: ENCLOSED

TYPE ELECTRIC AND OTHER LOGS RUN (See instructions)
RESISTIVITY, ACOUSTIC, DENSITY, NEUTRON, GAMMA RAY, ACOUSTIC BOREHOLE IMAGE, CALIPER, CBL & CEL

Was Well Cored: YES

CASING RECORD (Report all strings set in well)

Casing Size	Depth Set (MD)	Hole Size	Weight Lbs./Ft.	Sacks Cement	Amount Pulled
13-3/8"	2003'	17-1/2"	54.5#	1900	----
9-5/8" - 9-7/8"	9764'	12-1/4"	40. 48#	3163	----
5-1/2"	13,954'	8-1/2"	17. 20#	1250	----

LINER RECORD

Size	Top (MD)	Bottom (MD)	Sacks Cement	Screen (MD)

TUBING RECORD

Size	Depth Set (MD)	Packer Set (MD)
2-7/8"	9768'	9726'

PERFORATION RECORD (PRE-PERF'D CSG)

Depth Interval (MD)	Holes per ft.	Size and Type	Purpose
10,829'-13,954'	1*	.625" ID	PROD

*PERF'D EVERY OTHER JT FOR JTS 1-21.
FOR JTS 22-42. PERF'D 2 JTS THEN SKIP BLANK JT IN BTW

ACID, SHOT, FRAC., CEMENT SQUEEZE, Etc.

Amt. & Kind of Material Used	Depth Interval (MD)
------	------

PRODUCTION

Date First Production	Producing Method (Flowing, gas, lift, pumping - size & type of pump)	Well Status (Prod. or shut-in)
~~11-08-90~~ 11-07-90	FLWG	PROD

Date of Test	Hours Tested	Choke Size	Production For Test	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Oil Gravity - API (Corr.)
~~11-09-90~~ 11-08-90	8	30/64		501	~~401 EST.~~ 426	0	45° @ 60° F

Flow, Tubing Press.	Casing Pressure	Calculated 24-Hour Rate	Oil, Bbls.	Gas, Mcf.	Water, Bbls.	Gas-Oil Ratio
743	0		1503	~~1203~~ 1278	0	~~800~~ 850

DISPOSITION OF OIL & GAS (Purchaser and Transporter) REF: FORM 8 FILED 8-20-90
TEXACO TRADING & TRANSPORTATION INC. (TRANSPORTER)
SHELL OIL COMPANY (PURCHASER)

Test Witnessed By

LIST OF ATTACHMENTS

DIRECTIONAL SURVEY (2)

GEOLOGIC MARKERS

Name	Measured Depth of Formation	True Vertical Depth
GREENHORN	4393'	4392'
SWIFT	5625'	5623'
SPEARFISH	6675'	6673'
MINNELUSA	7513'	7511'
BUCKHORN	9278'	9275'
LODGEPOLE	9722'	9719'
LOWER LODGEPOLE	10,510'	10,507'
BAKKEN	10,518'	10,515'
THREE FORKS	10,532'	10,529'

DRILL STEM TEST DATA

OPEN HOLE DST DATE: 8-01-90

TEST INTERVAL: 10,484.3 - 10,534.7
PACKER DEPTHS: 10479, 10484, 10535, 10541
TOTAL WELL DEPTH: 10698

PRESSURE @ 10463'

IHP = 5891 PSI
START INIT FLOW - 2547.6 PSI
FIN INIT FLOW (6 MIN) - 2548.1 PSI
FIN SIP (575 MIN) - 6134 PSI
(NO SECOND FLOW OR SI PERIODS)
FHP = 5824 PSI
BHT = 242 F @ 10697'

I hereby swear or affirm that the information herein provided is true, complete and correct as determined from all available records.

JHSmitherman	J. H. SMITHERMAN, REGULATORY SUPV.	11-09-90
Signature	Title	Date

tate of TEXAS)
)ss
ounty of HARRIS)

On this 9th day of NOVEMBER, 19 90, before me personally appeared J. H. SMITHERMAN to me known as the person described in and who executed the foregoing instrument nd acknowledged that (s)he executed the same as his/her free act and deed.

Notary
Seal

NBoatman
Notary Public
State of TEXAS County of HARRIS
My Commission expires 11-06-1993

INSTRUCTIONS

1. Within thirty (30) days after the completion of a well, or recompletion of a well in a different pool, the original and three copies of his report must be filed with the North Dakota Industrial Commission, Oil and Gas Division.

2. Immediately after the completion or recompletion of a well in a pool or reservoir not then covered by an order of the commission, he original and three copies of this report must be filed with the North Dakota Industrial Commission, Oil and Gas Division.

3. The owner or operator shall file with the Oil and Gas Division two ~~three~~ copies of the following: all logs run, drill stem test reports and harts, formation water analysis and noninterpretive lithologic logs or sample descriptions if compiled.

Western Atlas International

WIRELINE SERVICES

DUAL LATEROLOG
MICRO LATEROLOG GAMMA

FILE NO.

API NO.
33-007-01213

COMPANY SHELL WESTERN EXPLORATION & PRODUCTION
WELL CONNELL NO.24-27
FIELD BUCKHORN
COUNTY BILLINGS STATE N.D.

LOCATION:
750' FSL & 1660' FWL
SEC 27 TWP 144N RGE 102W

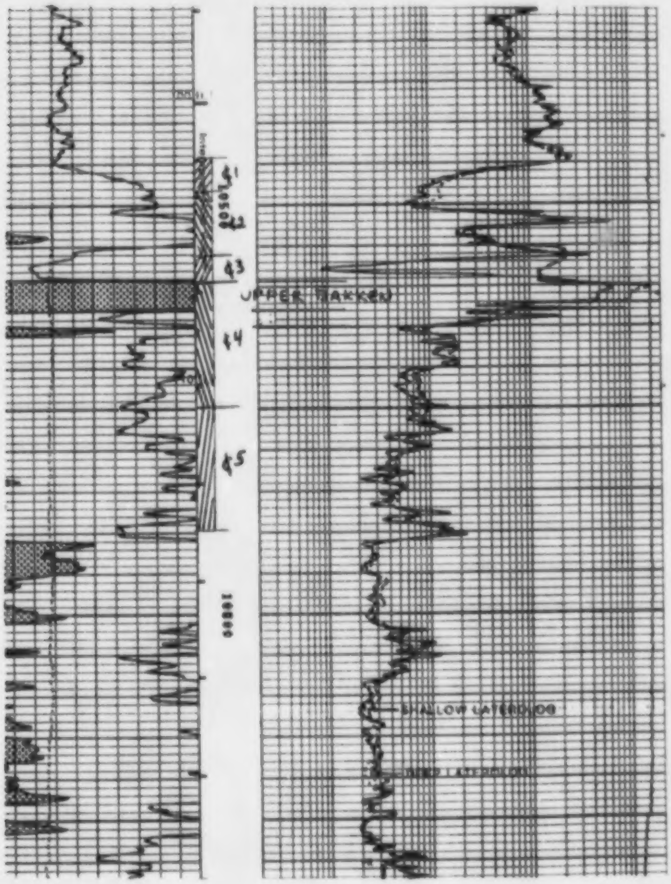
OTHER SERVICES

JAN 199
RECEIVED
ND OIL & GAS
DIVISION

PERMANENT DATUM GROUND LEVEL ELEV. 2342.2
LOGGING MEASURED FROM K.B. 19.7 FT. ABOVE P.D.
DRILLING MEASURED FROM KELLY BUSHING

ELEVATIONS
KB 2361.9
DF 2360.4
GL 2342.2

DATE	27-JULY-1990		
RUN	2		
SERVICE ORDER	52867		TIGHT HO
DEPTH-DRILLER	10698		
DEPTH-LOGGER	10698		
BOTTOM LOGGED INTERVAL	10695		
TOP LOGGED INTERVAL	9756		
CASING - DRILLER	9 5/8"	@ 9770	@
CASING - LOGGER	9756		
BIT SIZE	8 1/2"		
TYPE FLUID IN HOLE	SALT STARCH		
DENSITY / VISCOSITY	10.6	38	/
PH / FLUID LOSS	6.5	8.0	/
SOURCE OF SAMPLE	FLOWLINE		
RM AT MEAS. TEMP.	.051	@ 68	@
RMF AT MEAS. TEMP.	.042	@ 68	@
RMC AT MEAS. TEMP.	.064	@ 68	@
SOURCE OF RMF / RMC	MEAS.	CALC.	/
RM AT BHT	.016	@ 222	@
TIME SINCE CIRCULATION	8 HRS.		
MAX. REC. TEMP. DEG. F	222		
EQUIP. NO. / LOC.	HL-6274	CODY	/
RECORDED BY	NAUTIO		
WITNESSED BY	C.C. HILGERT		



Western Atlas International SERVICES

Z-DENSILOG NEUTR
GAMMA RAY

FILE NO.

API NO. 33-007-01213

COMPANY SHELL WESTERN EXPLORATION & PRODUCTION
WELL CONNELL NO.24-27
FIELD BUCKHORN
COUNTY BILLINGS STATE N.D.

LOCATION:
750' FSL & 1660' FWL

SEC 27 TWP 144N RGE 102W

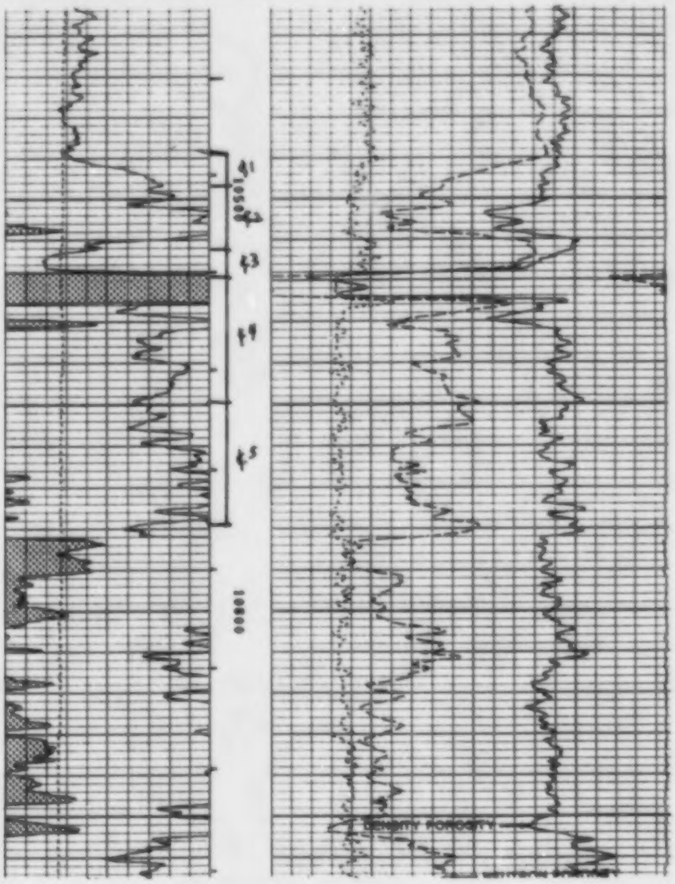
OTHER SERVICES

JAN 1991
RECEIVED
ND OIL & GAS
DIVISION

PERMANENT DATUM GROUND LEVEL ELEV. 2342.2
LOG MEASURED FROM K.B. 19.7 FT. ABOVE P.D.
DRILLING MEASURED FROM KELLY BUSHING

ELEVATIONS
KB 2361.9
DF 2360.4
GL 2342.2

DATE	27-JULY-1990		TIGHT HO
RUN	2		
SERVICE ORDER	52867		
DEPTH-DRILLER	10698		
DEPTH-LOGGER	10698		
BOTTOM LOGGED INTERVAL	10696		
TOP LOGGED INTERVAL	9756		
CASING - DRILLER	9 5/8"	@ 9770	@
CASING - LOGGER	9756		
BIT SIZE	8 1/2"		
TYPE FLUID IN HOLE	SALT STARCH		
DENSITY / VISCOSITY	10.6	30	
PH / FLUID LOSS	6.5	8.0	
SOURCE OF SAMPLE	FLOWLINE		
RM AT MEAS. TEMP.	.051	@ 68	@
RMF AT MEAS. TEMP.	.042	@ 68	@
RMC AT MEAS. TEMP.	.064	@ 68	@
SOURCE OF RMF / RMC	MEAS.	CALC.	
RM AT BHT	.016	@ 222	@
TIME SINCE CIRCULATION	12.5 HRS.		
MAX. REC. TEMP. DEG. F	234		
EQUIP. NO. / LOC.	HL-6274	CODY	
RECORDED BY	RAUTIO		
WITNESSED BY	C.C. HILGERT		



3886

Date : SEPTEMBER 13, 1990
Company : SHELL WESTERN E&P INC.
Lease : CONNELL
Well No. : 24-27
Field : BUCKHORN
State : BILLINGS COUNTY,NORTH DAKOTA
API No. : 33-007-01213-0000
Comments :

PLUG	DEPTH FT	GRAIN DEN G/CC	PHI %	WATER SAT %	OIL SAT %	AIR PERM MD
1	10479.5	2.696	0.2	224.6	281.9	0.022
2	10480.5	2.693	0.3	144.4	156.5	0.038
3	10481.5	2.691	0.2	28.9	367.3	0.024
4	10482.5	2.691	0.2	236.3	194.2	0.023
5	10483.5	2.711	1.4	76.4	19.8	0.79
6	10484.5	2.707	1.2	79.5	19.8	0.25
7	10485.5	2.698	0.6	108.3	76.2	0.022
8	10486.5	2.693	0.4	127.8	147.8	0.021
9	10487.5	2.702	1	91.7	19.4	0.031
10	10488.6	2.697	0.7	127.2	35.8	0.029
11	10489.5	2.694	0.2	222.8	111.6	0.019
12	10490.5	2.691	0.3	104	142.2	0.017
13	10491.5	2.695	0.6	90.3	101.2	0.016
14	10492.5	2.706	1.5	74.5	25	0.13
15	10493.5	2.712	2.4	81.6	9.4	0.55
16	10494.5	2.715	2.9	86.1	9.3	4.1
17	10495.5	2.719	3.3	55.3	44.2	0.3
18	10496.5	2.718	3.2	87.8	9	0.38
19	10497.5	2.721	3.8	85.6	7.8	
20	10498.5	2.717	3.4	78.6	14.2	45
21	10499.5	2.727	3.8	77.1	20.7	
22	10500.5	2.732	4.5	79.2	17.6	1.5
23	10501.5	2.733	4.4	83.6	9.7	
24	10502.5	2.698	1.7	30	57.5	52
25	10503.5	2.683	1.9	46.2	51.5	
26	10504.5	2.633	2.7	35.6	31.8	0.34
27	10505.5	2.641	2.7	26.8	34.1	0.037
28	10506.5	2.69	3.1	54.8	39.6	0.53
29	10507.5	2.709	3.1	49.3	37.7	
30	10508.5	2.588	4.1	25.8	29.8	0.042
31	10509.5	2.7	3.6	43.8	31.1	0.14
32	10510.5	2.707	2.7	46.5	36.3	22
33	10511.5	2.713	1.4	30.5	42.4	0.024
34	10512.5	2.794	2.7	23.2	43.4	0.035
35	10513.5	2.769	1.5	31.1	46.3	0.02
36	10514.5	2.74	2.4	19.6	41.9	0.018
37	10515.5	2.721	3.1	10.2	48.7	0.043
38	10516.6	2.715	4	9	41.8	0.034
39	10517.5	2.747	4.1	12.6	49.6	0.026
40	10518.5	2.716	4.3	8	57.6	0.026
	10520.0					
	10520.5					
	10521.0					

	10521.5					
	10522.0					
	10522.5					
	10523.0					
	10523.5					
	10524.0					
	10524.5					
	10525.5					
84	10526.5	2.735	2.6	6	53.4	0.019
85	10527.5	2.748	3.9	20.9	48	0.028
86	10528.5	2.771	5.1	18.2	48.5	0.024
87	10529.5	2.767	7.7	20.7	46.6	0.024
88	10530.5	2.732	8.4	49.1	30.2	
41	10531.5	2.792	6.2	36.8	40.9	17
42	10532.5	2.798	6	26.9	40.6	0.15
43	10533.6	2.809	5.8	27	41.9	0.059
44	10534.5	2.779	5.3	32.7	43.3	0.098
45	10535.5	2.792	5.2	49.7	41.4	
46	10536.5	2.79	5	38.2	39.3	0.061
47	10537.5	2.798	4.6	42.6	39.5	0.067
48	10538.5	2.804	4.9	31.9	42.9	0.11
49	10539.5	2.781	5.2	28.3	56.2	0.14
50	10540.5	2.789	5.6	46.5	41.6	0.11
51	10541.5	2.795	5.4	74.2	25.5	3.7
52	10542.5	2.797	5.4	62.9	34.2	0.084
53	10543.5	2.794	5.7	63.8	34.7	0.063
54	10544.6	2.793	5.5	76.1	21.1	0.062
55	10545.5	2.788	4.7	63.6	27.4	0.059
	10546.5					
	10547.5					
	10548.5					
56	10549.5	2.804	3.9	74.7	22	0.055
57	10550.6	2.79	4.6	70.3	29.3	0.078
58	10551.6	2.802	4.4	56.3	35	0.046
59	10552.5	2.799	4.2	50.4	38.9	0.05
60	10553.5	2.774	3.4	64.1	23.8	9.3
61	10554.5	2.787	4.3	60.4	36.7	0.051
62	10555.5	2.852	4.7	16.5	53.9	0.061
63	10556.5	2.794	6	35.2	40.1	0.059
64	10557.5	2.798	7.7	69.8	19.3	
65	10558.5	2.788	6.4	68.8	22.3	0.1
66	10559.6	2.806	4.8	34.4	43.4	4.8
67	10560.6	2.801	5.4	51.7	28.4	0.13
68	10561.5	2.79	8	78.6	14.8	145
69	10562.6	2.788	7.1	66.5	20.3	21
70	10563.6	2.805	4	32.6	43.2	0.044
71	10564.6	2.797	7.1	54.6	40.4	
72	10565.5	2.789	6.8	86.9	12.2	1
73	10566.5	2.788	6.2	88.8	7.5	38
74	10567.5	2.778	8.3	62.6	34.6	21
75	10568.5	2.787	5.6	83.6	13.5	3.7
76	10569.6	2.792	4.4	78	19.3	
77	10570.5	2.777	8.1	89.5	8.8	5.4
78	10571.5	2.811	3.2	77.3	19.5	2.8
79	10572.5	2.783	6.1	85.9	11.5	0.93
80	10573.5	2.769	7.5	82	15.2	0.18
81	10574.6	2.771	9.2	89.8	7.3	11
82	10575.5	2.796	2.4	82.8	14.7	0.039
	10576.5					
83	10577.5	2.777	6.2	90.1	7.8	7.8
	10578.5					

CD-61

WELL COMPLETION OR RECOMPLETION REPORT - FORM 6
INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
SFN 2468 (2-92)

Industrial Commission of N D
Oil and Gas Division
600 East Boulevard
Bismarck, ND 58505

MAY 1995
RECEIVED
ND OIL & GAS
DIVISION

Designate Type of Completion
☒ Oil Well ☐ Gas Well ☐ Other
☐ Work Over ☐ Deepened ☐ Plug Back

Well File No.	13772
Well Name and No.	PETERSON #1-26
Spacing (Unit Description)	320 Acres W/2
Field	Wildcat
Pool	
Wildcat, Development, Extension	Wildcat

Operator Continental Resources, Inc.		Phone Number (405)233-8955
Address P.O. Box 1032		
City Enid	State OK	Zip Code 73702

LOCATIONS (Show footages, quarter-quarter, section, township and range)

At Surface 260' FNL & 1800' FWL NE-NW 26-132N-106W	County Bowman
At Top Prod. Interval, Reported Below 836' FNL & 1811' FWL NE-NW 26-132N-106W	
At Total Depth 4543' FNL & 1778' FWL SE-SW 26-132N-106W	Welder's Verification No A-23

Date Spudded 4-8-95	Date TD Reached 5-11-95	Drilling Contractor & Rig. No. Nabor 350	Elevation (KB) 2868'	Total Depth (MD & TVD) 9,082' TVD 13,145' MD	Plug Back TD (MD & TVD) (see back) 9385' MD

Producing Interval(s), This Completion, Top, Bottom, Name (MD & TVD) Red River B φ 9430' MD 9116' TVD - 13,145' MD 9082' TVD	No. of DST's Run (see back) NA	Date Directional Survey Submitted
Type of Electric and Other Logs Run (See Instructions) CNLD, Phasor Induction, Cyberlook, Directional Survey, CBL	Was Well Cored? ☐ No XX Yes List intervals 9106'-9130'	

CASING RECORD (Report all strings set in well)

Casing Size	Depth Set (MD)	Hole Size	Weight (Lbs./Ft.)	Sacks Cement	Top of Cement
16"	60'	26"	42	60	Surface
9 5/8"	1421'	13 1/2"	36	525	Surface
7"	9405'	8 3/4"	23 & 26	850	4660'

LINER RECORD

Size	Top (MD)	Bottom (MD)	Sacks Cement

TUBING RECORD

Size	Depth Set (MD)	Anchor Set (MD)	Packer Set (MD)
2 7/8"	8526'		8534'

PERFORATION RECORD

Interval (MD)	Holes Per Ft	Potential (O&W)	Purpose	Acid, Frac, Sqz, etc.	Amount & Kind of Material Used
6 1/8" Open hole					
9405'-13,145'					

PRODUCTION

Date of First Production Through Permanent Wellhead 5-18-95	Producing Method (Flowing, gas lift, pumping - size & type of pump) Flowing					Well Status (Prod. or shut-in) Producing	
Date of Test 5-20-95	Hours Tested 24	Choke Size 18/64"	Production for Test	Oil (Bbls.) 497	Gas (Mcf.) 174	Water (Bbls.) 0	Oil Gravity - API (Corr.) 36.1
Flowing Tubing Pressure 300		Casing Pressure 0	Calculated 24 hour rate	Oil (Bbls.) 20.7	Gas (Mcf.) 174	Water (Bbls.) 0	Gas-Oil Ratio 350 (est)
Disposition of Oil & Gas (Purchaser & Transporter) KOCH Oil Company & KOCH Services, Inc.					Test Witnessed By Ken Cottrill		

List of Attachments/Comments

CD-62 Page 2
SFN 2468 (2-92)

GEOLOGICAL MARKERS

FORMATION	MD	TVD
Dakota	4502	
Piper	5374	
Pine Salt	5714	
Charles	7001	
Lodgepole	7850	
Interlake	8579	
Red River	9078	
Red River A ϕ	9094	
Red River B ϕ	9127	
Red River C ϕ	9183	
Red River D ϕ	9259	

PLUG BACK INFORMATION

TYPE OF PLUG	INTERVAL/DEPTH	SACKS CEMENT
Cmt	9346'-8310'	525

DRILL STEM TEST DATA

I hereby swear or affirm that the information herein provided is true, complete and correct as determined from all available records.

Signature	Title	Date
	Drilling Manager	5-22-95

STATE OF Oklahoma)
) ss
COUNTY OF Garfield)

Notary Seal

On May 22, 19 95, J.T. Tarkington, known to me to be the person described in and who executed the foregoing instrument, personally appeared before me and acknowledged that (s)he executed the same as a free act and deed.

Melissa Cook
Notary Public

My Commission Expires August 21, 1996

INSTRUCTIONS

1. Within thirty (30) days after the completion of a well, or recompletion of a well in a different pool, the original and three copies of this report must be filed with the Industrial Commission of North Dakota, Oil and Gas Division.
2. Immediately after the completion of a well in a pool or reservoir not then covered by an order of the commission, the original and three copies of this report must be filed with the Industrial Commission of North Dakota, Oil and Gas Division.
3. The owner or operator shall file with the Oil and Gas Division two copies of all logs run and three copies of the following: drill stem test reports and charts, formation water analysis and noninterpretive lithologic logs or sample descriptions if compiled.

CD-63

Schlumberger

COMPANY	CONTINENTAL RESOURCES, INC
WELL	PETERSON #1-26
FIELD	WILDCAT
COUNTY	BOWMAN
STATE	ORTH DAK

MAY 1995
RECEIVED
ND OIL & GAS
DIVISION

LOCATION: NE NW
260' FNL & 1800' FWL

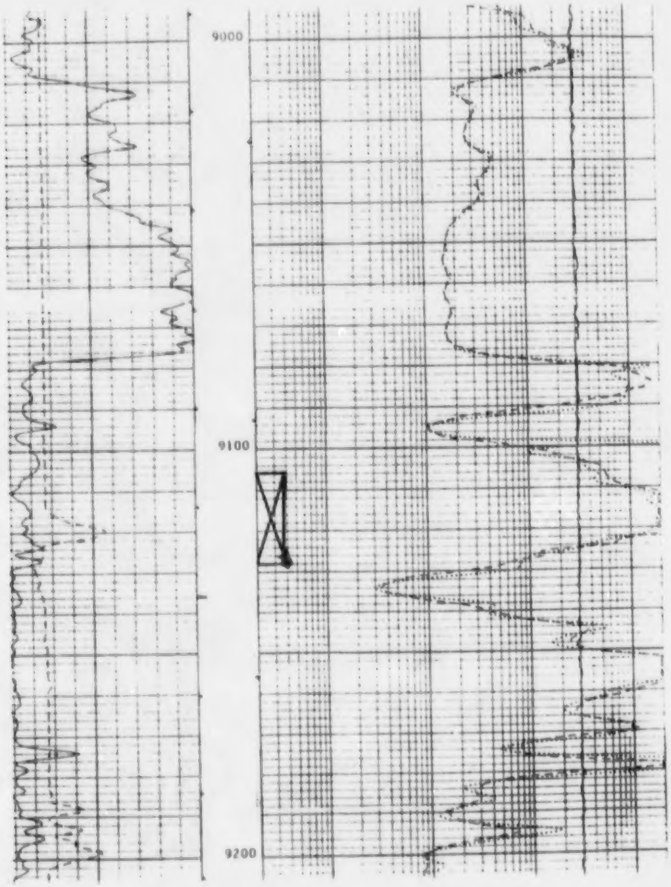
Other Services
DIT CNL
GR

API SERIAL NO	SECT	TWP	RANGE
33-011-00481	26	132N	106W

Permanent Datum	GL	Elev.	2847.0 F	
Log Measured From	KB	21.0 F	above Perm. Datum	
Drilling Measured From	KB			

Elev.: K.B. 28
D.F.
G.L. 28

Date	26-APR-1995	
Run No	ONE	
Depth Driller	9375.0 F	
Depth Logger (Schl.)	9388.0 F	
Btm. Log Interval	9382.0 F	
Top Log Interval	1426.0 F	
Casing-Driller	9 5/8 @ 1421.0 F	
Casing-Logger	1426.0 F	
Bit Size	8 3/4	
Type Fluid in Hole	OIL BASE	
Dens. / Visc.	9.50 LB/G	48.0 S
pH / Fld. Loss		8.0 C3
Fluid Level	0.0 F	
Elect. Stability	860.0 V	
Oil Water Ratio	78.0 %	
Salinity NaCl	36000.0 PPM	
Total Solids	13.0 %	
High Gravity Solids		
Circulation Ended	26-APR-1995 13:00	
Logger on Bottom	26-APR-1995 18:51	
Max. Rec. Temp.	194 DEGF	
Equip. / Location	8114	WILLISTON
Recorded By	C. CARPENTER	
Witnessed By	SANDRIDGE, TARKINGTON	



CD-64

FINAL PRINT

Schlumberger

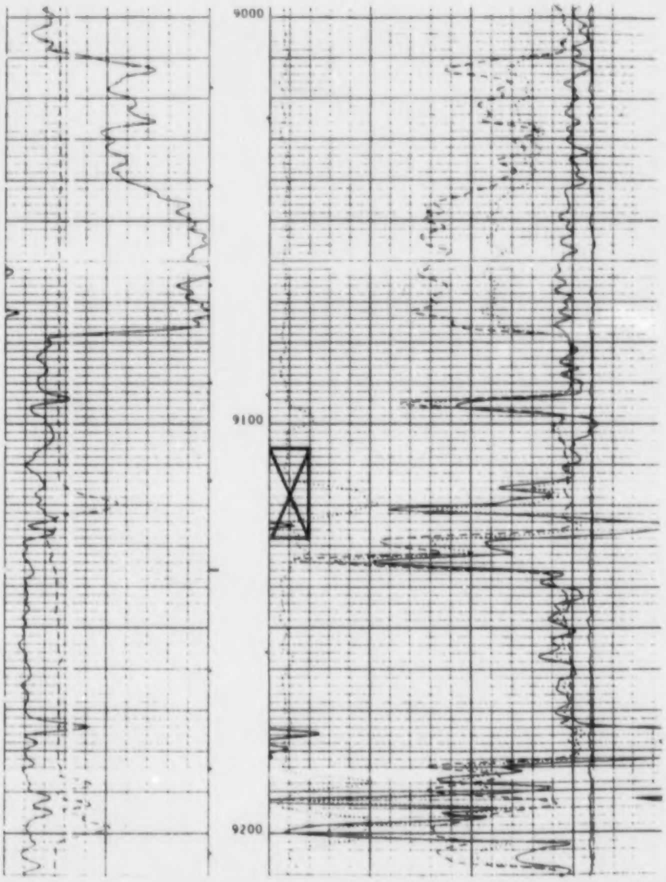
COMPENSATED NEUTRO
LITHO DENSITY

COMPANY	CONTINENTAL RESOURCES, INC.			
WELL	PETERSON #1-26			
FIELD	WILDCAT			
COUNTY	BOWMAN		NORTH DAK	
LOCATION	NE NW 260' FNL & 1800' FWL			Other Servic DITE GPIT
API SERIAL NO.	SECT.	TWP.	RANGE	
33-011-00481	26	132N	106W	

MAY 1995
RECEIVED
ND OIL & GAS
DIVISION

Permanent Datum	GL	Elev.	2847.0 F	Elev.: K.B.28
Log Measured From	KB	21.0 F	above Perm. Datum	D.F.
Drilling Measured From	KB			G.L.284

Date	26-APR-1995			
Run No.	ONE			
Depth Driller	9375.0 F			
Depth Logger (Schl.)	9388.0 F			
Btm. Log Interval	9347.0 F			
Top Log Interval	6900.0 F			
Casing-Driller	9 5/8 @ 1421.0 F	@	@	
Casing-Logger	1426.0 F			
Bit Size	8 3/4 @	@	@	
Type Fluid in Hole	OIL BASE			
Dens. / Visc.	9.50 LB/G	49.0 S		
pH / Fld. Loss		8.0 C3		
Fluid Level	0.0 F			
Elect. Stability	860.0 V			
Oil Water Ratio	78.0 %			
Salinity NaCl	36000.0 PPM			
Total Solids	10.0 %			
High Gravity Solids				
Circulation Ended	26-APR-1995 13:00			
Logger on Bottom	26-APR-1995 [illegible]			
Max. Rec. Temp.	194 DEGF			
Equip. / Location	8114	WILLISTON		
Recorded By	C. CARPENTER			
Witnessed By	SANDRIDGE/TARKINGTON			



CD-65
13772

CORELAB

CORE LABORATORIES

JUN 1995
RECEIVED
ND OIL & GAS
DIVISION

CORE ANALYSIS RESULTS

for

Continental Resources, Inc.

Peterson 1-26

Wildcat
Bowman Co., N. Dakota
57122-7938

The analyses, opinions or interpretations contained in this report are based upon observations and material supplied by the client for whose exclusive and confidential use this report has been made. The interpretations or opinions expressed represent the best judgment of Core Laboratories. Core Laboratories, however, assumes no responsibility and makes no warranty or representations, express or implied, as to the productivity, proper operations, or profitableness of any oil, gas, coal or other mineral, property, well or sand in connection with which such report is used or relied upon for any reason whatsoever. This report shall not be reproduced except in its entirety, without the written approval of Core Laboratories.

CORE LABORATORIES

Company : Continental Resources, Inc.
Well : Peterson 1-26
Location : SE SW Sec 26 T132N R106W
Co,State : Bowman, North Dakota

Field : Wildcat
Formation : Red River "B"
Coring Fluid : Inverted Mud
Elevation : 2868 KB

File No.: 57122-7938
Date : 27-Apr-1995
API No. :
Analysts: DF SS

CORE ANALYSIS RESULTS

(HYDROSTATIC CONFINEMENT)

SAMPLE NUMBER	DEPTH ft	PERMEABILITY (MAXIMUM) Kair md	PERMEABILITY (90 DEG) Kair md	NOB (800 psi) Kair md	POROSITY (HELIUM) %	SATURATION (PORE VOLUME) OIL %	SATURATION (PORE VOLUME) WATER %	GRAIN DENSITY gm/cc	DESCRIPTION
	Core No. 1 9106.0-9128.0 Cut 24.0' Rec. 22.0'								
	9106.0- 08.0								Ls -- Dense, No Analysis
1	9108.0- 09.0			0.028	2.9	40.9	49.0	2.87	Ls gry xln anhy
	9109.0- 11.0								Ls -- Dense, No Analysis
2	9111.0- 12.0			0.031	8.3	9.8	48.9	2.92	Ls gry xln v anhy
3	9112.0- 13.0			2.65	15.1	73.5	8.0	2.85	Dol brn suc
4	9113.0- 14.0	12.5	12.0	12.6	21.1	57.4	6.0	2.85	Dol brn suc
5	9114.0- 15.0			3.53	12.5	59.5	6.6	2.87	Dol brn suc
6	9115.0- 16.0			7.37	17.9	43.9	11.7	2.85	Dol brn suc anhy
7	9116.0- 17.0			0.030	4.4	6.2	49.5	2.79	Dol brn suc
8	9117.0- 18.0			12.3	23.9	30.4	44.5	2.80	Dol brn suc
9	9118.0- 19.0	9.52		11.3	27.9	32.8	39.6	2.84	Dol brn suc anhy
10	9119.0- 20.0			3.55	21.5	11.4	67.2	2.83	Dol brn suc anhy
11	9120.0- 21.0			0.376	12.4	8.5	54.3	2.83	Dol brn suc
	9121.0- 23.0								Ls -- Dense, No Analysis
12	9123.0- 24.0			0.056	5.0	24.4	10.8	2.78	Ls brn suc
	9124.0- 25.0								Ls -- Dense, No Analysis
13	9125.0- 26.0			0.044	2.7	35.4	23.6	2.75	Ls gry xln
	9126.0- 27.0								Ls -- Dense, No Analysis
14	9127.0- 28.0			0.017	1.0	51.5	14.7	2.72	Ls gry xln
	9128.0- 30.0								Lost core

Data, Plug&Full Dia. 1 - 1

CORE LABORATORIES

Company : Continental Resources, Inc.
Well : Peterson 1-26

Field : Wildcat
Formation : RED RIVER "B"

File No.: 57122-7938
Date : 27-Apr-1995

TABLE I

SUMMARY OF CORE DATA

ZONE AND CUTOFF DATA

ZONE:	
Identification ---------	Red River "B"
Top Depth ----------------	9104.0 ft
Bottom Depth -------------	9132.0 ft
Number of Samples --------	14
DATA TYPE:	
Porosity --------------	(HELIUM)
Permeability ----------	(MAXIMUM) Kair
CUTOFFS:	
Porosity (Minimum) -------	0.0 %
Porosity (Maximum) -------	100.0 %
Permeability (Minimum) ---	0.0000 md
Permeability (Maximum) ---	100000. md
Water Saturation (Maximum)	100.0 %
Oil Saturation (Minimum) -	0.0 %
Grain Density (Minimum) --	2.00 gm/cc
Grain Density (Maximum) --	3.00 gm/cc
Lithology Excluded -------	NONE

CHARACTERISTICS REMAINING AFTER CUTOFFS

ZONE:	
Number of Samples -----	14
Thickness Represented -	14.0 ft
POROSITY:	
Storage Capacity ------	168.6 ϕ-ft
Arithmetic Average ----	12.0 %
Minimum ---------------	0.3 %
Maximum ---------------	27.9 %
Median ----------------	12.4 %
Standard Deviation ----	±9.4 %
GRAIN DENSITY:	
Arithmetic Average ----	2.83 gm/cc
Minimum ---------------	2.72 gm/cc
Maximum ---------------	2.92 gm/cc
Median ----------------	2.84 gm/cc
Standard Deviation ----	±0.05 gm/cc

PERMEABILITY:	
Flow Capacity ---------	22.0 md-ft
Arithmetic Average ----	11.0 md
Geometric Average -----	10.9 md
Harmonic Average ------	10.8 md
Minimum ---------------	9.52 md
Maximum ---------------	12.5 md
Median ----------------	11.0 md
Standard Dev. (Geom) --	$K\cdot10^{\pm0.084}$ md
HETEROGENEITY (Permeability):	
Dykstra-Parsons Var. --	0.000
Lorenz Coefficient ----	0.151
AVERAGE SATURATIONS (Pore Volume):	
Oil -------------------	37.1 %
Water -----------------	31.6 %

CORE LABORATORIES

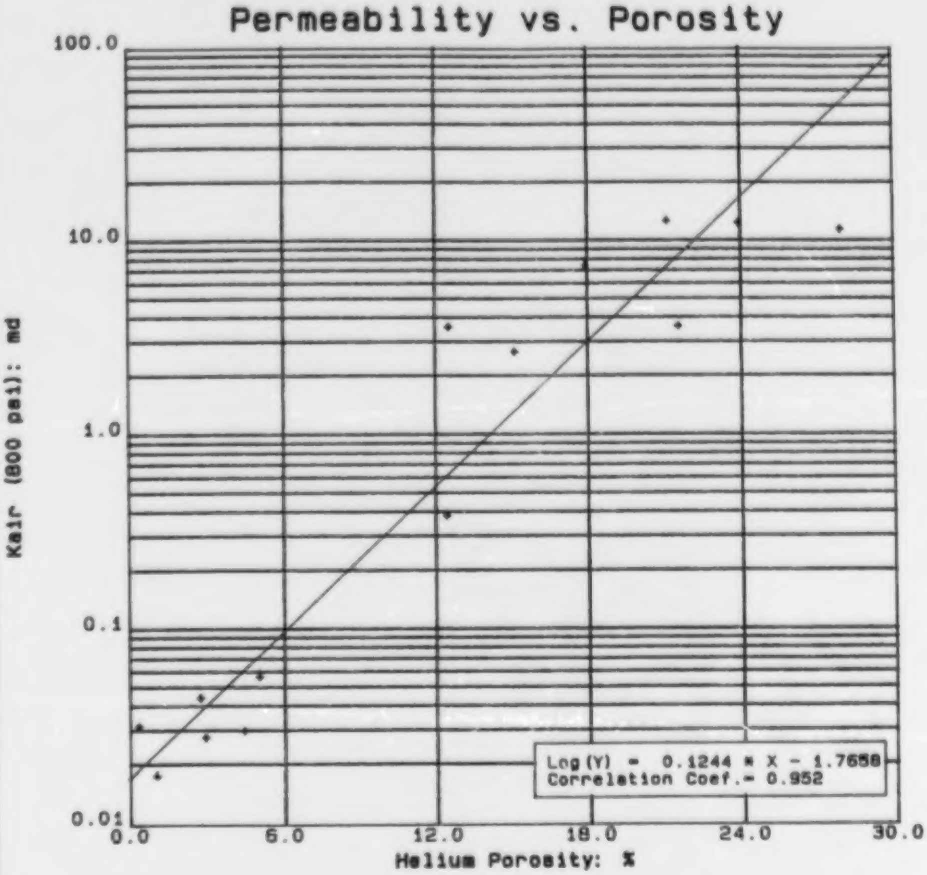
Company : Continental Resources, Inc.
Well : Peterson 1-26
Location : SE SW Sec 26 T132N R106W
Co,State : Bowman, North Dakota

Field : Wildcat
Formation : Red River "B"
Coring Fluid : Inverted Mud
Elevation : 2868 KB

File No.: 57122-7938
Date : 27-Apr-1995
API No. :
Analysts: DF SS

CMS - 200 TEST DATA

SAMPLE NUMBER	DEPTH ft	NOB PRESSURE psi	PORE VOLUME cc	POROSITY %	K∞ md	Kair(est) md	b (He) psi	BETA ft(-1)	ALPHA microns
1	9108.0	800.0			0.016	0.028	55.23	6.0596E14	3.14204E4
2	9111.0	800.0			0.026	0.031	14.54	7.8550E13	6.65537E3
3	9112.0	800.0			2.01	2.65	16.65	2.8013E10	1.80800E2
4	9113.0	800.0			10.1	12.6	11.11	1.44636E8	4.74195E0
5	9114.0	800.0			2.93	3.53	10.32	6.49046E9	6.14239E1
6	9115.0	800.0			6.05	7.37	10.54	1.46499E9	2.86300E1
7	9116.0	800.0			0.019	0.030	39.77	1.4408E15	9.03128E4
8	9117.0	800.0			9.56	12.3	13.33	5.04435E8	1.55706E1
9	9118.0	800.0			8.57	11.3	15.28	7.96431E8	2.20534E1
10	9119.0	800.0			2.43	3.55	23.78	1.2457E10	9.74283E1
11	9120.0	800.0			0.228	0.376	40.06	2.8530E11	2.09061E2
12	9123.0	800.0			0.029	0.056	65.13	1.2712E14	1.20260E4
13	9125.0	800.0			0.025	0.044	51.93	4.3854E14	3.60230E4
14	9127.0	800.0			0.013	0.017	28.79	1.4454E14	5.92577E3



Continental Resources, Inc.
Peterson 1-26
Wildcat
Bowman County, N. Dakota
Red River (9106.0-9128.0 feet)
Core 1
Core Laboratories 25-Apr-1995

- LEGEND -
Red River "B"

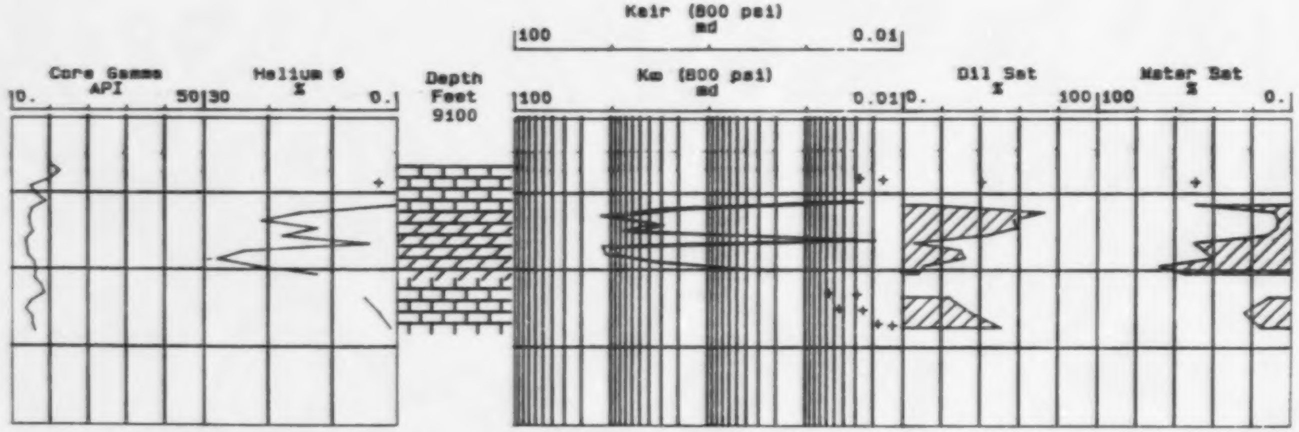
Correlation Coregraph

Continental Resources, Inc.
Peterson 1-26
Wildcat
Bowman County, N. Dakota
Red River (9106.0-9128.0 feet)
Core No. 1
Core Laboratories 25-Apr-1995

Vertical Scale
5.00 in = 100.0 ft

- Lithology Legend -

▦ Limestone ▨ Dolomite



"AMENDED" ƀ ×

WELL COMPLETION OR RECOMPLETION REPORT - FORM 6
INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
SFN 2468 (2-92)

Industrial Commission of N.D.
Oil and Gas Division
600 East Boulevard
Bismarck, ND 58505

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& GAS
DIVISION

Designate Type of Completion
☒ Oil Well ☐ Gas Well ☐ Other
☐ Work Over ☐ Deepened ☐ Plug Back

Operator: Citation Oil & Gas Corp.	Phone Number: (281) 469-9664

Address: 8223 Willow Place South, Suite 250

City: Houston,	State: Texas	Zip Code: 77070-5623

Well File No.: 14521
Well Name and No.: Stearns #14-15H
Spacing (Unit Description): Sec. 15, T129N, R106W
Field: Cedar Hills
Pool: Red River "B"
Wildcat, Development, Extension: Development

LOCATIONS (Show footages, quarter-quarter, section, township and range)

At Surface: 350' FSL & 350' FWL, SW SW, Sec. 15, T129N, R106W	County: Bowman
At Top Prod. Interval, Reported Below: 689' FSL & 689' FWL, SW SW Sec. 15, T129N, R106W	
At Total Depth: 4588' FSL & 4611' FWL, NE NE Sec. 15, T129N, R106W	Welder's Verification No.: -

Date Spudded: 12/9/96	Date TD Reached: 1/30/97	Drilling Contractor & Rig. No.: Caza, Rig #42	Elevation (KB): 2900'	Total Depth (MD & TVD): 13,262'/8296' TVD	Plug Back TD (MD & TVD) (see back): 7150' MD/TVD

Producing Interval(s), This Completion, Top, Bottom, Name (MD & TVD): Red River "B" / 8762' MD/8280' TVD - 13,262' MD/8296' TVD	No. of DST's Run (see back): -	Date Directional Survey Submitted: Attached
Type of Electric and Other Logs Run (See Instructions): CNL; CBL/GR/CCL	Was Well Cored? ☐ No ☒ Yes - List intervals: 8272'-8302'	

CASING RECORD (Report all strings set in well)

Casing Size	Depth Set (MD)	Hole Size	Weight (Lbs./Ft.)	Sacks Cement	Top of Cement
9-5/8"	1600'	13-1/2"	36#	725 Poz; 175 "G"	Surface
7"	8668'	8-1/2"	26#	630 Poz; 375 "G"	1460'

LINER RECORD / TUBING RECORD

Size	Top (MD)	Bottom (MD)	Sacks Cement	Size	Depth Set (MD)	Anchor Set (MD)	Packer Set (MD)
				2-7/8"	7526'	7402'	-

PERFORATION RECORD

Interval (MD)	Holes Per Ft.	Potential (O&W)	Purpose	Acid, Frac, Sqz, etc.	Amount & Kind Material Used
8762' - 13,262'	--	O & W	Horizontal	-	--
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PRODUCTION

Date of First Production Through Permanent Wellhead: 2/13/97	Producing Method (Flowing, gas lift, pumping - size & type of pump): Pumping - 1-3/4" x 2-1/2" x 24 - RHBM	Well Status (Prod. or shut-in): Producing

Date of Test: 2/14/97	Hours Tested: 10	Choke Size: N/A	Production for Test	Oil (Bbls.): 89	Gas (Mcf.): *	Water (Bbls.): 382	Oil Gravity - API (Corr.): 30.0°
Flowing Tubing Pressure: SITP - 40 psi		Casing Pressure: SICP - 30 psi	Calculated 24 hour rate	Oil (Bbls.): 214	Gas (Mcf.): *	Water (Bbls.): 917	Gas-Oil Ratio: *

Disposition of Oil & Gas (Purchaser & Transporter): Koch Oil - Purchaser; Koch Pipeline - Transporter	Test Witnessed By: Citation Oil & Gas Corp.

List of Attachments/Comments
Directional Survey; GR Log; Phasor Ind. Log; CNL Log; Core Analysis Report

* Gas rate and GOR pending meter installation; will submit as soon as available

CD-72 Page 2
SFN 2468 (2-92)

GEOLOGICAL MARKERS

FORMATION	MD	TVD
Charles	6402'	6398'
Base Greenpoint	6492'	6488'
Mission Canyon	6716'	6711'
Lodgepole	7182'	7177'
Carrington SH	7582'	7573'
Devonian	7687'	7671'
Silurian	7810'	7780'
Stonewall	8288'	8148'
Gunton	8330'	8174'
Stoney Mtn	8426'	8222'
Red River	8568'	8266'
Red River B	8760'	8279'

PLUG BACK INFORMATION

TYPE OF PLUG	INTERVAL/DEPTH	SACKS CEMENT
Plug #1 OH VPH	8,100' - 8,514'	140
Plug #2 OH VPH	7,200' - 7,900'	355
ST #1	7,968' - 8,620'	294

DRILL STEM TEST DATA

NO DST's RUN ON THIS WELL

PER YOUR REQUEST DATED 3/5/97:

1. Pilot hole drilled to TD of ~~8454~~ 8545' KB; 8542' WLM (for cores)
2. Cemented 8514' - 8100' and 7900' - 7200'
3. Drilled hard cement to 1st kick-off point @7342' and drilled to 8658'
4. Cemented 8620' - 7960'
5. Drilled hard cement to 2nd kick-off point @8318' and drilled to a TD of 13,262'
6. Sidetrack intervals:
   a. 1st sidetrack 7342' - 8658'; plugged 7960'-8620'
   b. 2nd sidetrack 8318' - 13,262'

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At present no gas production is being recorded, however a meter is being installed at which time a GOR test will be submitted.

I hereby swear or affirm that the information herein provided is true, complete and correct as determined from all available records.

Signature	Title	Date
Debra Harris (Debra Harris	Regulatory Analyst	2/28/97

STATE OF Texas)
ss
COUNTY OF Harris)

RENEE HARRELL
Notary Public, State of Texas
My Commission Expires March 2, 1999

On Feb. 28, 19 97, Debra Harris, known to me to be the person described in and who executed the foregoing instrument, personally appeared before me and acknowledged that (s)he executed the same as a free act and deed.

Renee Harrell
Notary Public

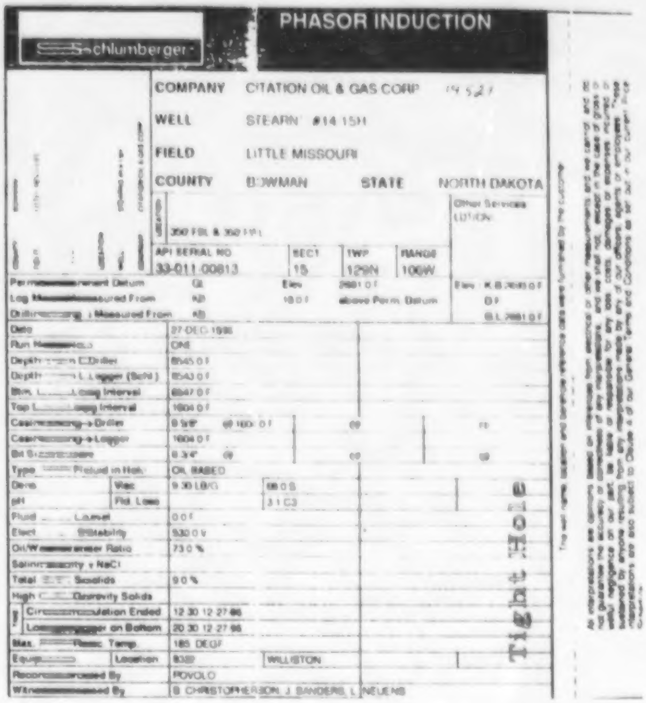
My Commission Expires 3-2-99

INSTRUCTIONS

1. Within thirty (30) days after the completion of a well, or recompletion of a well in a different pool, the original and three copies of this report must be filed with the Industrial Commission of North Dakota, Oil and Gas Division.

2. Immediately after the completion of a well in a pool or reservoir not then covered by an order of the commission, the original and three copies of this report must be filed with the Industrial Commission of North Dakota, Oil and Gas Division.

3. The owner or operator shall file with the Oil and Gas Division two copies of all logs run and three copies of the following: drill stem test reports and charts, formation water analysis and noninterpretive lithologic logs or sample descriptions if compiled.



Schlumberger

PHASOR INDUCTION

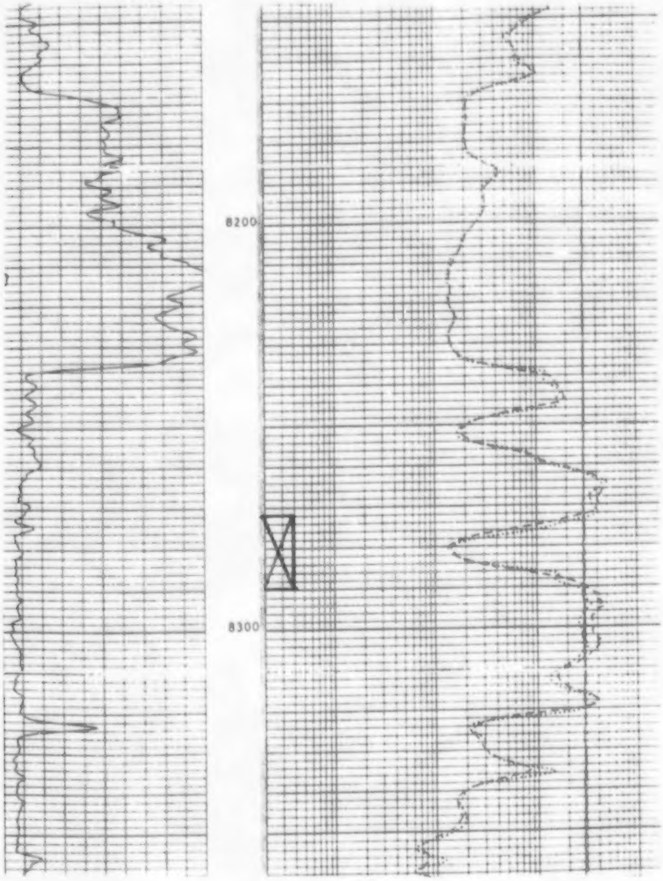
COMPANY	CITATION OIL & GAS CORP 19527
WELL	STEARN #14 15H
FIELD	LITTLE MISSOURI
COUNTY	BOWMAN **STATE** NORTH DAKOTA
Location	350 FSL & 350 FWL
Other Services	LDT/CN

API SERIAL NO	SECT	TWP	RANGE
33-011-00813	15	129N	106W

Permanent Datum	GL	Elev	2881.0 F	Elev.	K.B. 2895.0 F
Log Measured From	KB	16.0 F	above Perm. Datum		D.F.
Drilling Measured From	KB				G.L. 2881.0 F

Date	27-DEC-1986		
Run No.	ONE		
Depth Driller	8545.0 F		
Depth Logger (Schl.)	8543.0 F		
Btm. Log Interval	8547.0 F		
Top Log Interval	1604.0 F		
Casing-Driller	9 5/8" @ 1600.0 F	@	@
Casing-Logger	1604.0 F		
Bit Size	8 3/4" @	@	@
Type Fluid in Hole	OIL BASED		
Dens. / Visc.	9.30 LB/G / 68.0 S		
pH / Fld. Loss	3.1 C3		
Fluid Level	0.0 F		
Elect. Stability	530.0 V		
Oil/Water Ratio	73.0 %		
Salinity, NaCl			
Total Solids	9.0 %		
High Gravity Solids			
Circulation Ended	12.30 12-27-86		
Logger on Bottom	20.30 12-27-86		
Max. Rec. Temp.	185. DEGF		
Equip. / Location	8332 / WILLISTON		
Recorded By	POVOLO		
Witnessed By	B. CHRISTOPHERSON, J. SANDERS, L. NEUENS		

Tight Hole



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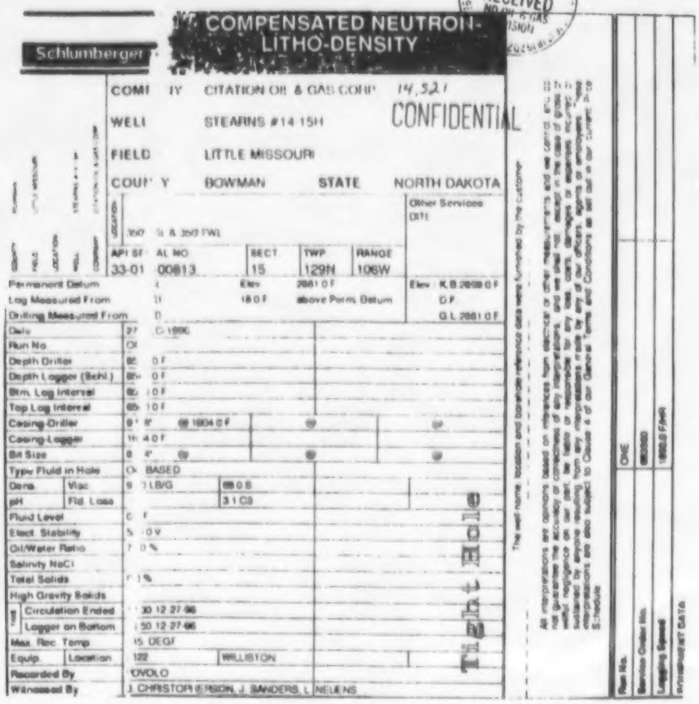

MAR 1997 RECEIVED ND OIL & GAS DIVISION

Schlumberger

COMPENSATED NEUTRON-LITHO-DENSITY

14,521

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Tight Hole

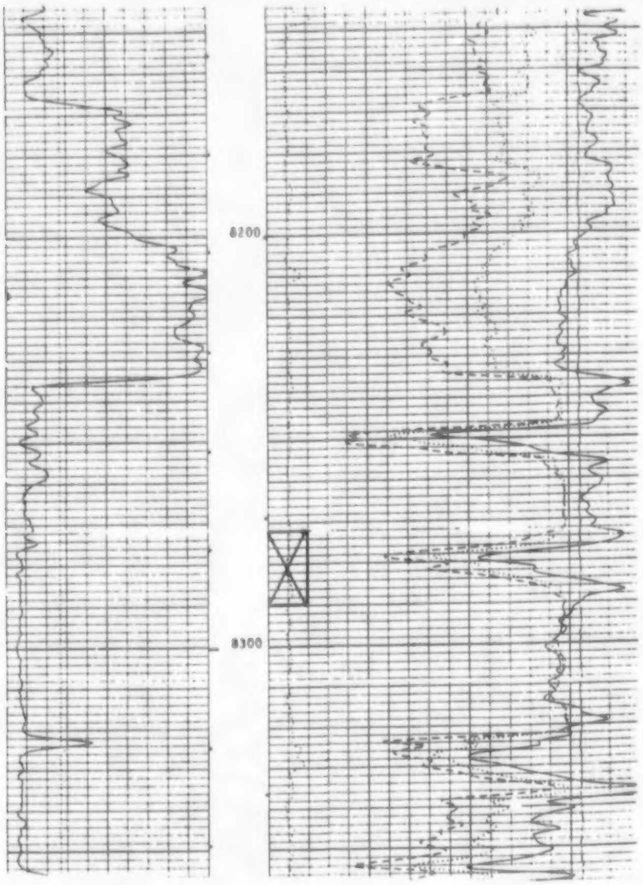
COMI IY	CITATION OIL & GAS CORP				
WELI	STEARNS #14-15H				
FIELD	LITTLE MISSOURI				
COUI Y	BOWMAN	STATE	NORTH DAKOTA		
LOCATION	350' 'L & 350' FWL			Other Services	DITI
API SE AL NO		SECT.	TWP	RANGE	
33-01	00813	15	129N	106W	

Permanent Datum	I	Elev	2881 0 F	Elev	K.B 2899 0 F
Log Measured From	1I	18 0 F	above Perm. Datum		D.F
Drilling Measured From	D				G.L 2881 0 F

Date	27 C-1996		
Run No	OI		
Depth Driller	8£ 0 F		
Depth Logger (Schl.)	8£ 0 F		
Btm. Log Interval	8l 0 F		
Top Log Interval	85 10 F		
Casing-Driller	9' 8" @ 1804 0 F	@	@
Casing-Logger	1t 4 0 F		
Bit Size	8 4" @	@	@
Type Fluid in Hole	O BASED		
Dens. / Visc.	9 1 LB/G / 68 0 S		
pH / Fld. Loss	/ 3 1 C3		
Fluid Level	C F		
Elect. Stability	5 0 V		
Oil/Water Ratio	7 0 %		
Salinity NaCl			
Total Solids	1 %		
High Gravity Solids			
Time Circulation Ended	30 12 27-96		
Time Logger on Bottom	50 12 27-96		
Max. Rec. Temp.	15 DEGF		
Equip. / Location	122 / WILLISTON		
Recorded By	OVOLO		
Witnessed By	J. CHRISTOPHERSON, J. SANDERS, L. NELENS		

The well name, location and borehole reference data were furnished by the customer.

Run No.	ONE
Service Order No.	
Logging Speed	
SCHLUMBERGER DATA	



CD-75

MAR 1997

CONVENTIONAL CORE ANALYSIS

Citation Oil & Gas Corporation
Stearns 14-15 H Well
Bowman County, North Dakota
SRS 2269/RSH 3560

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Natural Core Gamma Radiation Log
Specific Permeability To Gas (Steady-State Method)
Porosity and Grain Density (Boyle's Law Method)
Fluid Saturations (Dean-Stark Method)
Lithological Description Of Core Plug Samples

Table 1

CONVENTIONAL CORE ANALYSIS

Citation Oil & Gas Corporation
Stearns 14 - 15 H Well
Bowman County, North Dakota
SRS 2269/RSH 3560

Core 1
Depth Interval: 8272.0 - 8302.0 ft.

Sample	Depth (ft.)	Porosity (%BV)	Permeability to gas (md)		Grain Density (g/cc)	Saturation (%PV) Water	Oil	Gas	Lithological Description
N 900	8272.4	0.2	< 0.001		2.74	88.3	0.0	11.7	Ls gry dns microxln
N 901	8273.5	0.3	0.002		2.73	100.0	0.0	0.0	Ls gry dns microxln tr anhy incl
N 902	8274.6	0.5	0.045	*	2.84	62.5	0.0	37.5	Dol gry dns microxln sdy i.p. sli calc filled frac
N 903	8275.8	2.7	0.003		2.84	67.8	6.9	25.3	Dol lt gry dns microxln sli calc sli shly thn sh strk
N 904	8276.4	0.9	**		2.81	83.5	0.0	16.5	Dol lt tan dns crpxln abd filled frac
N 905	8277.0	4.8	7.23	*	2.84	77.3	21.9	0.8	Dol lt gry dns microxln sli calc
N 906	8277.6	5.6	0.010		2.84	45.8	39.8	14.4	Dol tan-brn dns microxln
N 907	8278.0	6.7	0.012		2.84	79.5	11.2	9.3	Dol gry dns microxln sli calc sli shly i.p.
N 908	8278.7	11.9	0.163		2.83	33.6	39.8	26.6	Dol dk brn microxln tr p.p. vug
N 909	8279.3	14.2	0.366		2.83	51.8	30.9	17.3	Dol gry brn-brn microxln sli shly tr styl
N 910	8279.8	12.0	26.7	*	2.83	70.4	22.5	7.1	Dol lt brn microxln sli slty filled frac
N 911	8280.4	14.4	0.404		2.83	70.1	10.9	19.0	Dol lt brn-brn microxln sli slty
N 912	8281.4	11.2	0.128		2.83	91.0	3.7	5.3	Dol lt gry microxln sli calc
N 913	8282.1	8.5	0.062		2.82	87.3	8.4	4.3	Dol lt gry microxln sli calc
N 914	8283.2	13.0	0.535		2.78	85.1	10.0	4.9	Dol lt gry microxln calc
N 915	8284.2	9.8	0.121		2.82	84.6	7.8	7.6	Dol lt gry microxln sli calc styl
N 916	8284.5	8.3	3.08	*	2.83	78.8	12.0	9.2	Dol lt gry microxln sli calc anhy tr filled & open frac
N 917	8284.8	6.5	0.035	*	2.83	76.0	21.7	2.3	Dol lt gry microxln dns sli calc lge anhy incl filled frac
N 918	8285.9	2.8	2.86	*	2.84	59.5	33.2	7.3	Dol lt gry microxln dns vsli calc filled frac
N 919	8286.0	3.9	0.017		2.82	61.5	24.1	14.4	Dol mott gry-buff microxln dns vsli calc lge cht incl
N 920	8286.6	5.3	4.38	*	2.83	60.7	36.1	3.2	Dol gry-buff microxln dns lge cht incl filled frac
N 921	8287.0	4.6	1.12		2.87	31.8	62.4	5.8	Dol gry-brn microxln sli shly i.p. tr anhy
N 922	8287.5	1.2	0.117	*	2.84	83.8	8.7	7.5	Dol gry dns micro-vfxln lge anhy incl filled frac
N 923	8288.0	4.0	1.45	*	2.81	67.6	30.4	2.0	Dol mott gry-wht micro-fxln sli calc lge cht incl filled frac
N 924	8288.5	2.8	0.066		2.76	71.8	18.9	9.3	Ls mott buff-gry dns microxln dol i.p.
N 925	8289.1	2.6	0.011		2.75	79.5	12.9	7.6	Ls mott buff-gry dns microxln dol i.p.
N 926	8289.5	1.9	0.009		2.77	80.5	15.4	4.1	Ls mott buff-gry dns microxln dol i.p.

Table 1 (continued)

CONVENTIONAL CORE ANALYSIS

Citation Oil & Gas Corporation
Stearns 14 - 15 H Well
Bowman County, North Dakota
SRS 2269/RSH 3560

Core 1
Depth Interval: 8272.0 - 8302.0 ft.

Sample	Depth (ft.)	Porosity (%BV)	Permeability to gas (md)	Grain Density (g/cc)	Saturation (%PV) Water	Oil	Gas	Lithological Description
N 927	8290.2	1.4	0.091 *	2.77	79.3	13.4	7.3	Ls mott buff-gry dns micro-vfxln filled & open frac
N 928	8290.4	1.1	0.002	2.77	79.5	20.1	0.4	Ls mott lt gry-gry dns microxln dol i.p.
N 929	8290.9	0.6	0.002	2.75	75.5	15.1	9.4	Ls mott lt gry-gry dns microxln sdy
N 930	8291.4	1.4	0.053 *	2.73	71.6	26.6	1.8	Ls lt gy dnc crp-vfxln sdy fos filled frac
N 931	8291.9	0.5	0.007	2.71	87.6	2.9	9.5	Ls lt gry dns crpxln sli sdy fos
N 932	8292.5	1.1	1.28	2.72	70.6	1.8	27.6	Ls lt gry dns crp-microxln sli sdy styl
N 933	8293.1	1.5	0.211	2.77	79.6	3.7	16.7	Ls mott lt-dk gry microxln sdy styl
N 934	8294.0	1.5	0.013	2.74	70.6	11.5	17.9	Ls gry dns microxln sdy anhy fos
N 935	8295.0	0.6	0.082 *	2.70	96.1	1.8	2.1	Ls gry dns microxln fos filled frac
N 936	8296.1	1.5	0.150 *	2.73	71.7	7.1	21.2	Ls mott buff-gry dns microxln sli sdy sli shly styl filled frac
N 937	8297.1	1.0	0.002	2.71	56.6	6.0	37.4	Ls lt gry dns microxln sli sdy tr anhy
N 938	8298.1	1.5	0.016	2.73	81.4	10.2*	8.4	Ls lt gry dns microxln sli sdy tr anhy
N 939	8299.0	1.4	0.101 *	2.71	69.8	10.9	19.3	Ls lt gry dns microxln tr anhy filled frac
N 940	8299.5	1.8	0.067	2.72	66.6	20.6	12.8	Ls lt gry dns microxln crsxln i.p. sli sdy styl tr sml vug
N 941	8300.2	3.6	0.074	2.70	50.6	19.8	29.6	Ls lt gry microxln sli sdy anhy incl abd sml vug fos

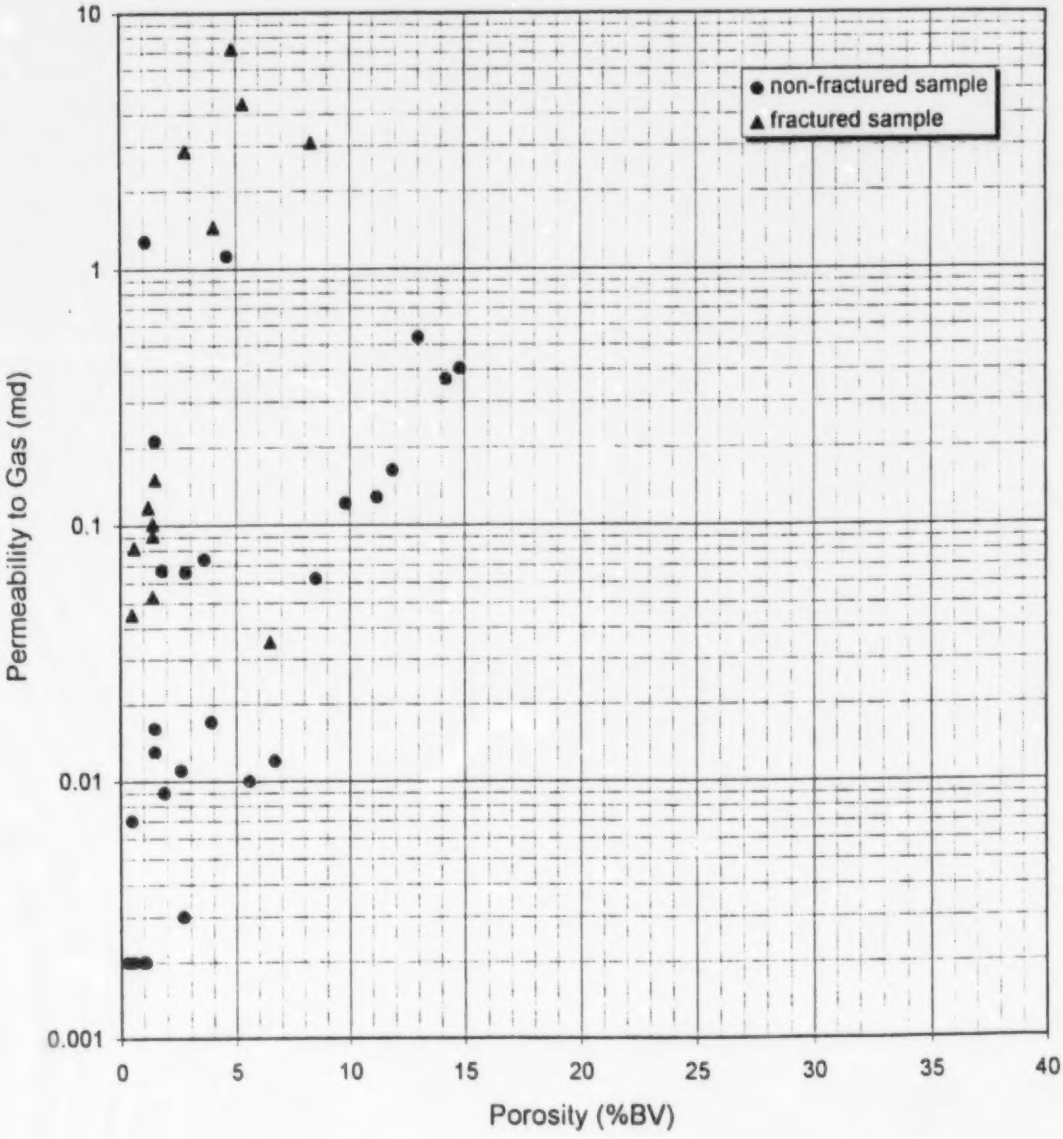
* Denotes sample contains hairline and/or filled fracture. Permeability to gas may be anomalously high.

** Denotes sample is non-cylindrical. Permeability to gas indeterminable

Figure 1

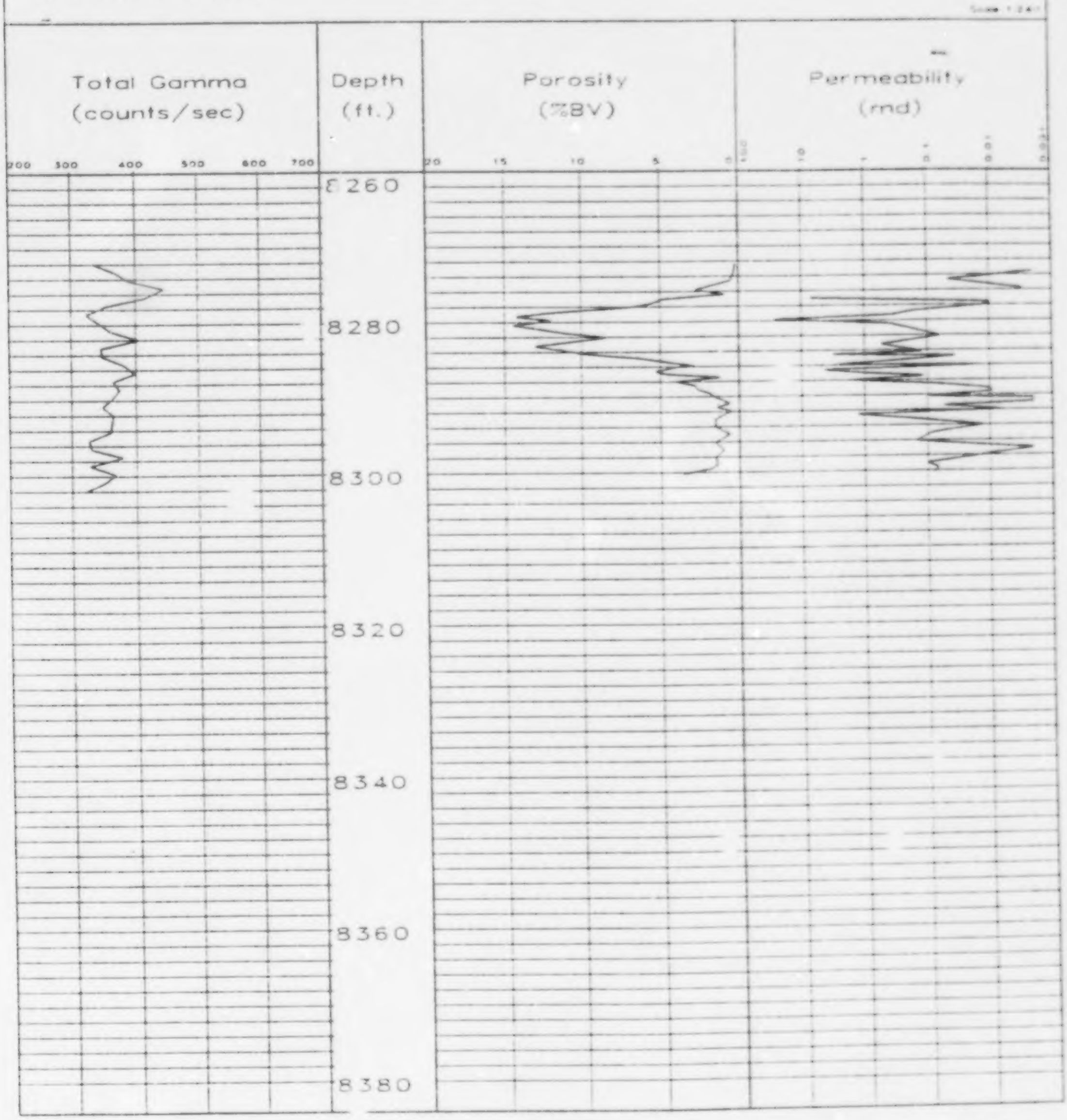
PERMEABILITY - POROSITY RELATIONSHIP

Citation Oil & Gas Corporation
Stearns 14 - 15 H Well
Bowman County, North Dakota
SRS 2269/RSH 3560



TOTAL GAMMA LOG

Citation Oil & Gas Corporation
Stearns 14-15 H Well
Bowman County, North Dakota
SRS 2269/RSH 3560



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CD-80

WELL COMPLETION OR RECOMPLETION REPORT - FORM 6

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
SFN 2468 (2-92)

Industrial Commission of N.D.
Oil and Gas Division
600 East Boulevard
Bismarck, ND 58505

Designate Type of Completion ☒ Oil Well ☐ Gas Well ☐ Other ____ ☐ Work Over ☐ Deepened ☐ Plug Back		
Operator: Eagle Operating Inc.	Phone Number: 701-385-4244	
Address: Box 853		
City: Kenmare	State: ND	Zip Code: 58746

Well File No.: 14725

Well Name and No.: E-M Larson #9-11 R

Spacing (Unit Description): SW¼ 9 163-87

Field: Newporte

Pool: Cambro-Ord.

Wildcat, Development, Extension: Developement

LOCATIONS (Show footages, quarter-quarter, section, township and range)

At Surface: 1597' FWL 1542' FSL NESW 9 163 87				County: Renville
At Top Prod. Interval, Reported Below: Same as above				
At Total Depth: Same as above				Welder's Verification No.
Date Spudded: 5 8-21-97	Date TD Reached: 10-7-97	Drilling Contractor & Rig. No.: Wolverine #33	Elevation (KB): 1811'	Total Depth (MD & TVD): 9650'
				Plug Back TD (MD & TVD) (see back): 9614'
Producing Interval(s), This Completion, Top, Bottom, Name (MD & TVD): Deadwood Sand @9572'-9576'				No. of DST's Run (see back): 3
				Date Directional Survey Submitted
Type of Electric and Other Logs Run (See Instructions): GR/CBL DLL/DAL/GR/CAL CNL				Was Well Cored? ☐ No ☒ Yes - List intervals: See attachment

CASING RECORD (Report all strings set in well)

Casing Size	Depth Set (MD)	Hole Size	Weight (Lbs./Ft.)	Sacks Cement	Top of Cement
8 5/8"	996'	12¼"	24#	335 sks	surface
5½"	9650'	7 7/8"	20#,23#,17#	2100 sks	2650'

LINER RECORD

Size	Top (MD)	Bottom (MD)	Sacks Cement

TUBING RECORD

Size	Depth Set (MD)	Anchor Set (MD)	Packer Set (MD)
2 7/8"	9604'	9544'	

PERFORATION RECORD

Interval (MD)	Holes Per Ft.	Potential (O&W)	Purpose	Acid, Frac, Sqz, etc.	Amount & Kind of Material Used
9572'-9576'	2 SPF		Breakdown	-	-

PRODUCTION

Date of First Production Through Permanent Wellhead: 10-28-97		Producing Method (Flowing, gas lift, pumping - size & type of pump): pump 2½x1 3/4x20 RHBC SV TC/TC				Well Status (Prod. or shut-in): Prod.	
Date of Test: 11-9-97	Hours Tested: 24	Choke Size: na	Production for Test	Oil (Bbls.): 35	Gas (Mcf.): TSTM	Water (Bbls.): 140	Oil Gravity - API (Corr.): 30.2 @ 60°
Flowing Tubing Pressure: 0		Casing Pressure: 0	Calculated 24 hour rate	Oil (Bbls.): 35	Gas (Mcf.): TSTM	Water (Bbls.): 140	Gas-Oil Ratio: TSTM
Disposition of Oil & Gas (Purchaser & Transporter): Murphy Oil Power Fuels					Test Witnessed By: Bob Mau		

List of Attachments/Comments

Core and DST Intervals DST's #1, #2, #3 test results

Geologic Markers

WESTERN ATLAS

GAMMA RAY LOG
CALIPER LOG

FILE NO:

API NO:

COMPANY EAGLE OPERATING, INC.
WELL E-W LARSON 89-11-R
FIELD NEWPORTE
COUNTY RENVILLE STATE NORTH DAKOTA

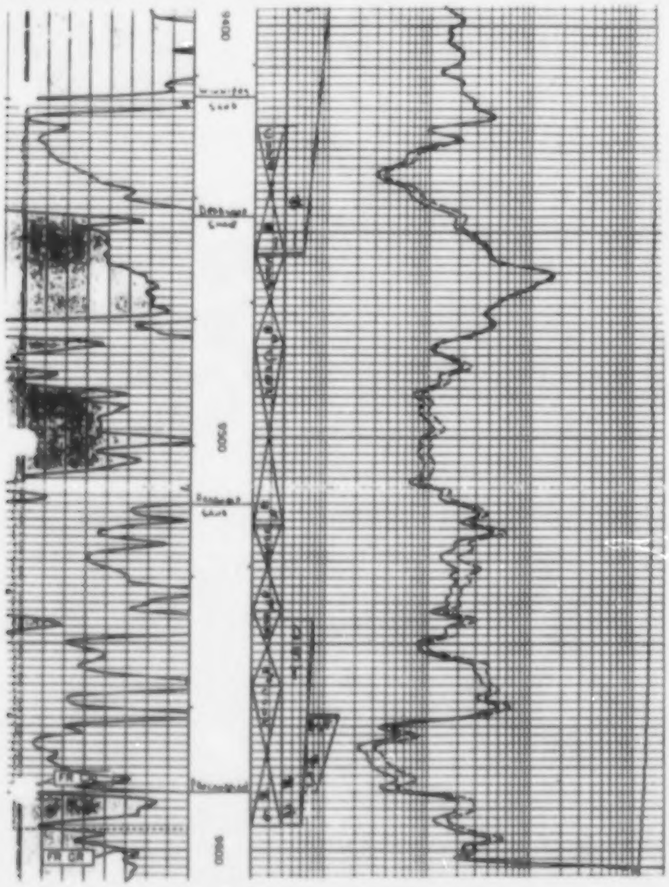
LOCATION:
1542' FSL & 1507' FWL
NE/SW
SEC 9 TWP 163N RGE 87W

OTHER SERVIC
DAL/GR/CAL
ZDL/CN/GR

PERMANENT DATUM G.L. ELEVATION 1794 FT
LOG MEASURED FROM K.B. 17 FT ABOVE P.D.
DRILL. MEAS. FROM K.B.

ELEVATIONS
KB 1811 FT
DF 1810 FT
GL 1794 FT

DATE	9-OCT-1997	
RUN	ONE	
SERVICE ORDER	200266	
DEPTH DRILLER	9650 FT	
DEPTH LOGGER	9660 FT	
BOTTOM LOGGED INTERVAL	9648 FT	
TOP LOGGED INTERVAL	1006 FT	
CASING - DRILLER	8.625 IN @996 FT	
CASING LOGGER	1006 FT	
BIT SIZE	7.875 IN	
TYPE OF FLUID IN HOLE	SALT STARCH	
DENSITY / VISCOSITY	10.0 LB/G | 38 S	
PH / FLUID LOSS	7.0 | 10.0 C3	
SOURCE OF SAMPLE	MUDTANK	
RM AT MEAS. TEMP.	.057 OHMM @61 DEGF	
RMF AT MEAS. TEMP.	.046 OHMM @61 DEGF	
RMC AT MEAS. TEMP.	.072 OHMM @61 DEGF	
SOURCE OF RMF / RMC.	MEAS. | CALC.	
RM AT BHT	.018 OHMM @195 DEGF	
TIME SINCE CIRCULATION	7 HRS.	
MAX. RECORDED TEMP.	195 DEGF	
EQUIP. NO. / LOCATION	HL-6530 | DKSN	
RECORDED BY	VERN RAUTIO	
WITNESSED BY	BOB MAU/ROY CLEMENT	



WESTERN ATLAS

COMPENSATED NEUTRON LOG
GAMMA RAY LOG

FILE NO:

API NO:

COMPANY EAGLE OPERATING, INC.
WELL E-M LARSON #9-11-R
FIELD NEWPORTE
COUNTY RENVILLE STATE NORTH DAKOTA

LOCATION:
1542' FSL & 1597' FWL
NE/SW

SEC 9 TWP 163N RGE 87W

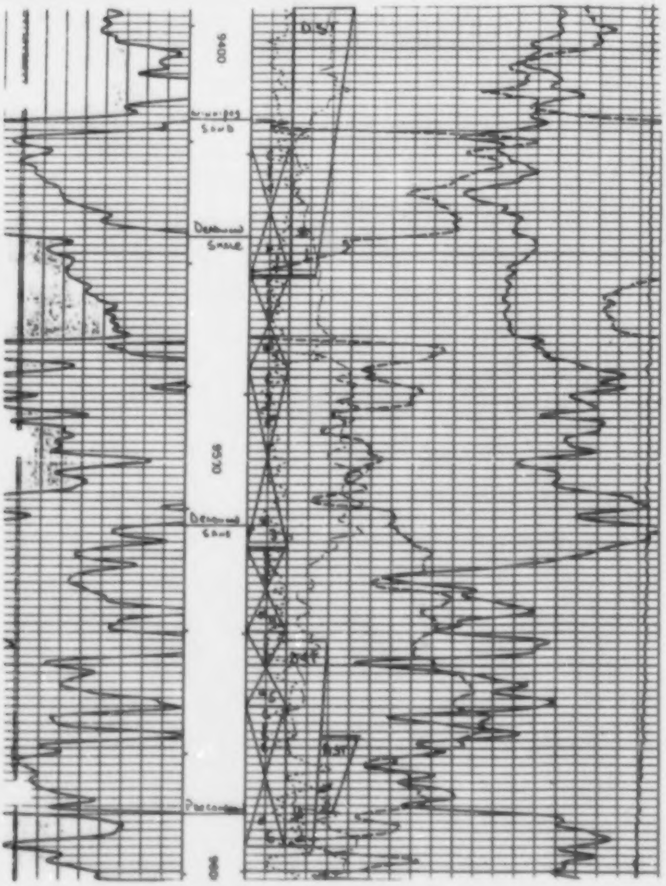
OTHER SERVIC
DLL/GR/CAL
DAL/GR/CAL

PERMANENT DATUM G.L. ELEVATION 1794 FT
LOG MEASURED FROM K.B. 17 FT ABOVE P.D.
DRILL. MEAS. FROM K.B.

ELEVATIONS	
KB	1811 FT
DF	1810 FT
GL	1794 FT

DATE	9-OCT-1997		
RUN	ONE		
SERVICE ORDER	200266		
DEPTH DRILLER	9650 FT		
DEPTH LOGGER	9660 FT		
BOTTOM LOGGED INTERVAL	9657 FT		
TOP LOGGED INTERVAL	4300 FT		
CASING - DRILLER	8.625 IN	@996 FT	●
CASING LOGGER	1006 FT		
BIT SIZE	7.875 IN		
TYPE OF FLUID IN HOLE	SALT STARCH		
DENSITY / VISCOSITY	10.0 LB/G	38 S	
PH / FLUID LOSS	7.0	10.0 C3	
SOURCE OF SAMPLE	MUDTANK		
RM AT MEAS. TEMP.	.057 OHMM	@61 DEGF	●
RMF AT MEAS. TEMP.	.046 OHMM	@61 DEGF	●
RMC AT MEAS. TEMP.	.072 OHMM	@61 DEGF	●
SOURCE OF RMF./ RMC.	MEAS.	CALC.	
RM AT BHT	.018 OHMM	@195 DEGF	●
TIME SINCE CIRCULATION	14 HRS.		
MAX. RECORDED TEMP.	203 DEGF		
EQUIP. NO. / LOCATION	HL-6530	DKSN	
RECORDED BY	VERN RAUTIO		
WITNESSED BY	BOB MAU/ROY CLEMENT		

Source File: pm-07.pdf



CD-3

CORE STRIP LOG

WellSight Systems Inc.

Scale 1:48 Imperial

Well Name:	E-M LARSON NO. 9-11-R		
.ocation:	NE SW SECTION 9-T163N-R87W, RENVILLE COUNTY, ND		
Contractor:	WOLVERINE DRILLING RIG #33		
Core #:	1		
Formation:	WINNIPEG SAND		
Core Interval:	From: 9418'	Cut:	31'
	To: 9449'	Recovered:	31'
Bit type:	BIT TECH CN403R		
Size:	7 7/8"		
Coring Time:	16 hours		

Printed by STRIP.LOG from WellSight Systems Inc. 1-800-447-1534

ROCK TYPES

- Anhy
- Bent
- Brec
- Cht
- Clyst
- ■ Coal
- Congl
- Dol
- Gyp
- Igne
- Lmst
- Meta
- Mrlst
- Salt
- Shale
- Shcol
- Shgy
- Sltst
- Ss
- Till
- ☐ Blank

ACCESSORIES

MINERAL

- Anhy
- Arggrn
- Arg
- B Bent
- Bit
- Brecfrag
- Calc
- Carb
- Chtdk
- Chtlt
- Dol
- Feldspar
- Ferrpel
- Ferr
- Glau
- Gyp
- Hvymin
- K Kaol
- Marl
- Minxl
- Nodule
- Phos
- P Pyr
- Salt
- Sandy
- Silt
- Sil
- S Sulphur
- Tuff

FOSSIL

- Algae
- Amph
- Belm
- Bioclst
- Brach
- Bryozoa
- Cephal
- Coral
- Crin
- Echin
- Fish
- Foram
- F Fossil
- Gastro
- Oolite
- Ostra
- Pelec
- Pellet
- Pisolite
- Plant
- Strom

STRINGER

- Anhy
- Arg
- Bent
- Coal
- Dol
- Gyp
- Ls
- Mrst
- Sltstrg
- Ssstrg

TEXTURE

- BS Boundst
- C Chalky
- CX Cryxln
- E Earthy
- FX Finexln
- GS Grainst
- L Lithogr
- MX Microxln
- MS Mudst
- PS Packst
- WS Wackest

OTHER SYMBOLS

POROSITY TYPE

- E Earthy
- Fenest
- Fracture
- Inter
- Moldic
- O Organic
- P Pinpoint
- V Vuggy

SORTING

- W Well
- M Moderate
- P Poor

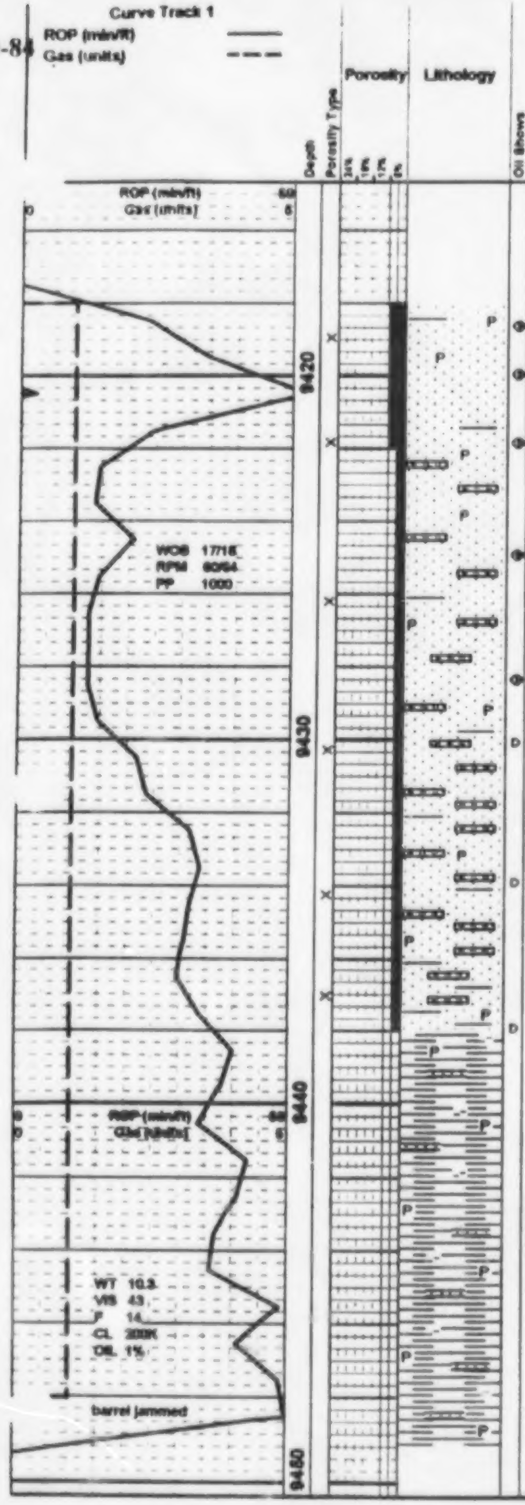
ROUNDING

- R Rounded
- Submd
- Subang
- A Angular

OIL SHOWS

- ● Even
- Spotted
- O Ques
- D Dead

CD-84



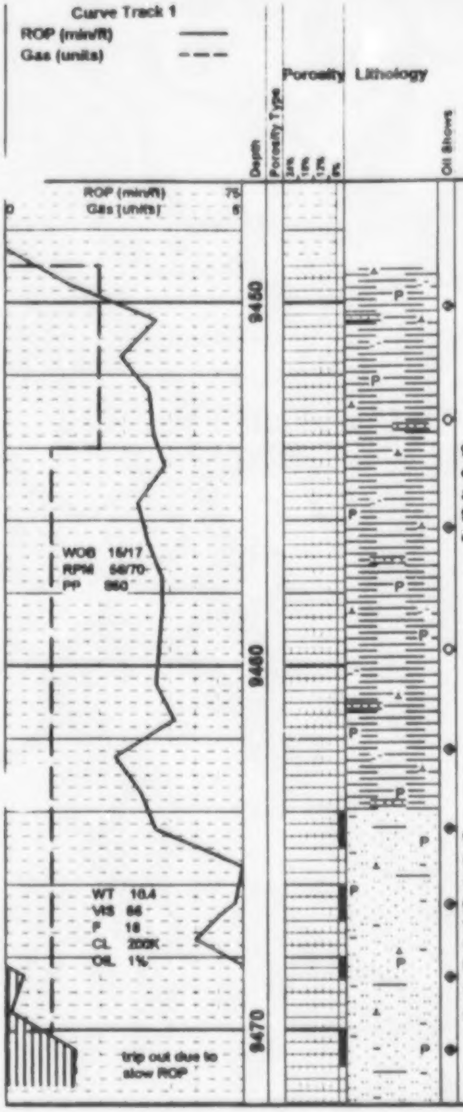
Geological Descriptions

9418' - 9422' Sandstone: white to light brown, fine to coarse grained, sub angular to sub rounded, poorly sorted, poor to fair consolidation with siliceous cement, abundant dark brown shale partings and small Pyrite nodules, poor intergranular porosity, light brown oil stain, dull yellow fluorescence, yellow green streaming cut

9422' - 9229' Sandstone: white to light gray, very fine to coarse grained, sub rounded to sub angular, poorly sorted, fairly consolidated with siliceous to calcareous cement, silty, dark brown shale partings and laminations, finely disseminated to small nodular Pyrite, very poor inter granular porosity, predominantly silt plugged, slight trace light brown spotty oil stain, dull yellow fluorescence, slow yellow green streaming cut

9429' - 9438' Sandstone: white to light brown, salt & peppered with abundant dark gray to black accessory minerals, very fine to coarse grained, sun rounded to sub angular, very poor sorting, fair to good consolidation with siliceous to calcareous cement, silty and grading to siltstone, finely disseminated to small nodular Pyrite, very poor visual porosity, predominantly silt plugged, dark brown dead oil stain with no fluorescence or solvent cuts, abundnat dark brown shale laminations at base

9438' - 9449' Shale: dark graybrown to dark brown, firm to brittle, abundnat finely disseminated Pyrite, silty to sandy with abundant thin Sandstone lenses



Geological Descriptions

9449' - 9464' SHALE: dark brown to graybrown, firm to brittle, abundant finely disseminated Pyrite & nodules, silty with occasional thin Sandstone lenses, abundant white to light orange calcite veins with inclined bedding, no fluorescence to dull yellow spotty fluorescence with instant bluewhite streaming cut

9464' - 9472' SANDSTONE: medium brown to graybrown, salt & peppered with black minerals, fine to coarse grained, sub rounded to sub angular, poorly sorted, well consolidated with siliceous cement, silty to shaly with abundant gray to graygreen shale clast, abundant finely disseminated Pyrite and nodules, very poor visual porosity, predominantly plugged with silt, light brown spotty to uniform oil stain, dull yellow fluorescence, instant bluewhite cut, grading in part to

SILTSTONE: light to medium gray, graygreen, firm, slightly calcareous, abundant gray to graygreen shale clast, laminated in part with inclined bedding

CD-8

CORE STRIP LOG

WellSight Systems Inc.

Scale 1:48 Imperial

Well Name: E-M LARSON NO. 9-11-R
.ocation: NE SW SECTION 9-T163N-R87W, RENVILLE COUNTY, ND
Contractor: WOLVERINE DRILLING RIG NO. 33
Core #: 3
Formation: DEADWOOD
Core Interval: From: 9472' Cut: 42'
To: 9514' Recovered: 43'
Bit type: BIT TECH CN403R
Size: 7 7/8"
Coring Time: 35.5 hrs

Printed by STRIP.LOG from WellSight Systems Inc. 1-800-447-1534

ROCK TYPES

Anhy
Bent
Brec
Cht
Clyst
Coal
Congl
Dol
Gyp
Igne
Lmst
Meta
Mrlst
Salt
Shale
Shcol
Shgy
Sltst
Ss
Till
Blank

ACCESSORIES

MINERAL
Anhy
Arggrn
Arg
B Bent
Bit
Brecfrag
Calc
Carb
Chtdk
Chtlt
Dol
Feldspar
Ferrpel
Ferr
Glau
Gyp
Hvymin
K Kaol
Marl
Minxl
Nodule
Phos
P Pyr
Salt
Sandy
Silt
Sil
S Sulphur
Tuff

FOSSIL
Algae
Amph
Belm
Bioclst
Brach
Bryozoa
Cephal
Coral
Crin
Echin
Fish
Foram
F Fossil
Gastro
Oolite
Ostra
Pelec
Pellet
Pisolite
Plant
Strom

STRINGER
Anhy
Arg
Bent
Coal
Dol
Gyp
Ls
Mrst
Sltstrg
Sststrg

TEXTURE
BS Boundst
C Chalky
CX Cryxln
e Earthy
FX Finexln
GS Grainst
L Lithogr
MX Microxln
MS Mudst
PS Packst
WS Wackest

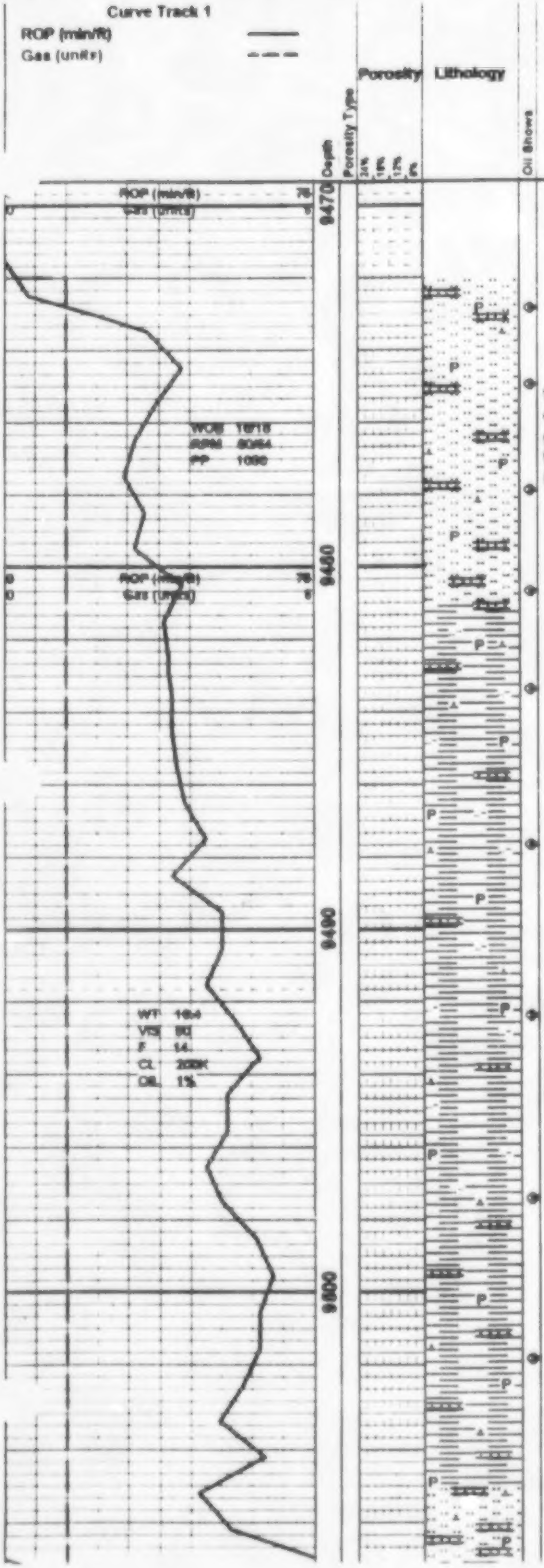
OTHER SYMBOLS

POROSITY TYPE
E Earthy
Fenest
Fracture
X Inter
Moldic
O Organic
P Pinpoint
V Vuggy

SORTING
W Well
M Moderate
P Poor

ROUNDING
R Rounded
r Subrnd
a Subang
A Angular

OIL SHOWS
Even
Spotted
O Ques
D Dead



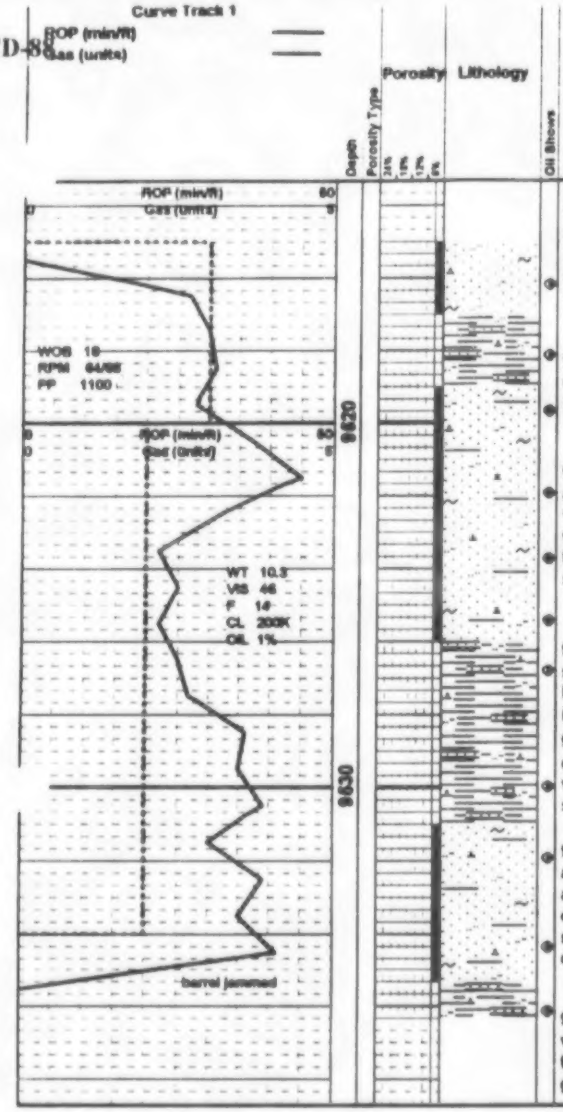
Geological Descriptions

9472' - 9481 SILTSTONE: dark gray to graygreen, firm, abundant finely disseminated Pyrite and black minerals, very sandy in part and grading to very fine grained Sandstone, calcareous in part, no fluorescence to occaasional dull yellow spotty fluorescence, bluewhite streaming cut

9481' - 9505' SHALE: dark gray to graygreen, firm to brittle, waxy, slightly calcareous, silty to sandy, common thin Sandstone lenses, abundant finely disseminated Pyrite and occasional nodules, inclined bedding in part, dull spotty yellow fluorescence, bluewhite streaming cut

9505' - 9507' SILTSTONE: gray to graygreen with orange to orangebrown calcite, abundant Pyrite and black minerals, calcareous, sandy and grading to very fine grained Sandstone

CD-88



Geological Descriptions

9515' - 9517' SANDSTONE: gray to light brown, salt and peppered with dark gray to black minerals, glauconitic, sub angular, very fine to medium grained, poor to fair sorting, well consolidated, siliceous to calcareous cement, silty, very poor visual porosity, light brown spotty oil stain, dull yellow fluorescence, yellow green streaming cut

9517' - 9519' SHALE: light gray, firm to brittle, waxy, slightly calcareous, very silty with thin Sandstone lenses, trace light brown spotty oil stain, dull yellow fluorescence, yellow green streaming cut

9519' - 9526' SANDSTONE: light gray to brown, salt & peppered with abundant black minerals, glauconitic, sub angular to sub rounded, very fine to fine grained with occasional medium grains, fair sorting, well consolidated with siliceous to calcareous cement, silty, abundant thin dark gray Shale laminae, very poor visual porosity, light brown oil stain, dull yelowl fluorescence, yellow green streaming cut

9526' - 9528' SHALE: light gray, firm, waxy, slightly calcareous, very silty and grading to Siltstone with thin Sandstone lenses, trace light brown spotty oil stain, dull yellow fluorescence, yellow green streaming cut

9528' - 9531' SHALE: light to medium gray, firm, waxy, slightly calcareous, laminated to nodular, abundant thin Sandstone laminae, very silty in part and grading to Siltstone, trace light brown spotty oil stain, dull yellow fluorescence, yellow green streaming cut

9531' - 9535.5' SANDSTONE: light to medium gray, light brown, salt and peppered with abundant black minerals and glauconite, sub angular to sub rounded, very fine to fine grained, fair sorting, well consolidated with siliceous to calcareous cement, silty, thin dark gray shale laminae, very poor visual porosity, light brown spotty oil stain, dull yellow fluorescence, yellow green streaming cut

9535.5' - 9536.5' SHALE: medium gray, firm, waxy, slightly calcareous, very silty and grading to Siltstone, occasional Sandstone lenses, trace light brown spotty oil stain, dull yellow fluorescence, yellow green streaming cut

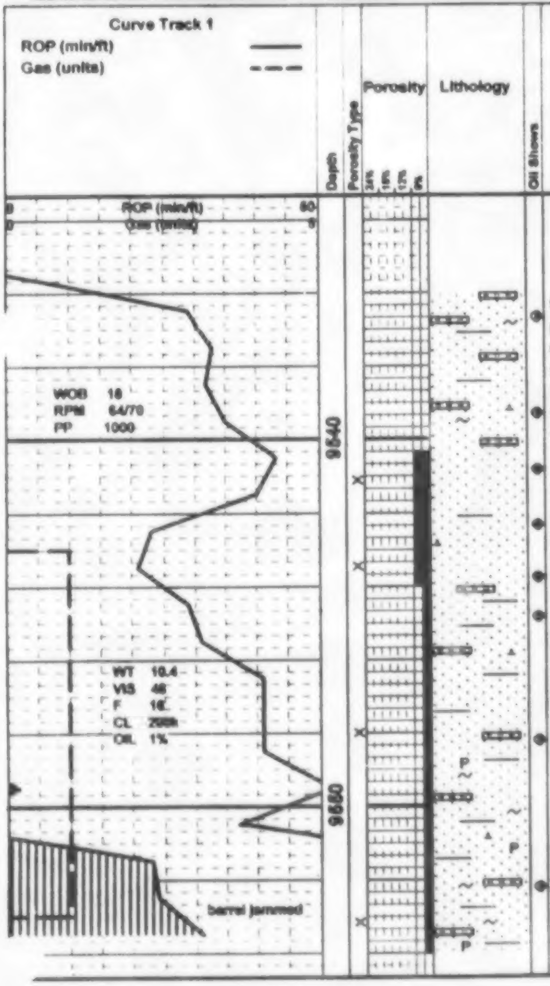
CORE STRIP LOG

WellSight Systems Inc.

Scale 1:48 Imperial

Well Name:	E-M LARSON NO. 9-11-R
Location:	NE SW SECTION 9-T163N-R87W, RENVILLE COUNTY, ND
Contractor:	WOLVERINE DRILLING RIG NO.33
Core #:	5
Formation:	DEADWOOD SAND
Core Interval:	From: 9536' Cut: 18'
	To: 9554' Recovered: 18'
Bit type:	BIT TECH CN403R
Size:	7 7/8"
Coring Time:	12 3/4 hrs

Printed by STRIP.LOG from WellSight Systems Inc. 1-800-447-1534



Geological Descriptions

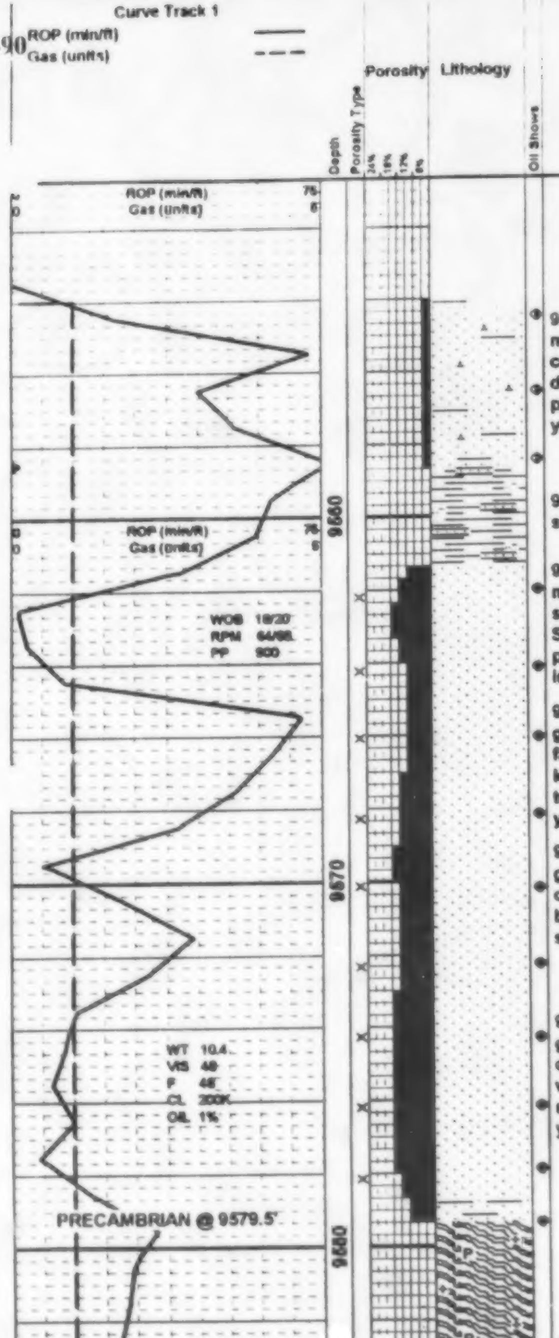
9536' - 9540.5' SANDSTONE: light gray to graybrown, salt and peppered with black minerals and glauconite, very fine to fine grained, sub angular, fair sorting, well consolidated with siliceous cement, slightly calcareous, no visual porosity, grading to Siltstone, burrowed in part, abundant thin, dark gray Shale laminae, trace light brown spotty oil stain, dull yellow fluorescence, moderate yellow streaming cut

9540.5' - 9544' SANDSTONE: light brown, very fine to fine grained, sub angular to sub rounded, fair sorting, poor to fair consolidation, slightly calcareous, poor intercrystalline porosity, scattered thin Shale laminae and dark minerals, light brown oil stain, dull yellow fluorescence, moderate yellow streaming cut

9544' - 9548' SANDSTONE: gray to gray brown, very fine to medium grained, sub angular to sub rounded, poor to fair sorting, well consolidated with siliceous to calcareous cement, burrowed, thin gray Shale laminae through out, grading to Siltstone, minor black minerals, very poor visual porosity, light brown spotty oil stain, dull yellow fluorescence, modeate yelow streaming cut

9548' - 9554' SANDSTONE: gray to graybrown, salt and peppered with abundant black minerals and glauconite, very fine to medium grained, sub angular to sub rounded, poorly sorted, well consolidated with siliceous cement, slightly calcareous, grading to Siltstone with abundant gray to graygreen Shale laminae, Pyritic, very poor visual porosity, light brown spotty oil stain, dull yellow fluorescence, moderate yellow streaming cut

CD-90



Geological Descriptions

9554' - 9558.5' SANDSTONE: lt brown to graybrown, very fine to medium grained, sub angular to sub rounded, poorly sorted, well consolidated with siliceous to calcareous cement, abundant light to dark gray shale laminae with inclined bedding, very poor visual porosity, light brown spotty oil stain, dull yellow fluorescence, instant yellowgreen streaming cut

9558.5' - 9561.25' SHALE: light to medium gray, firm to brittle, waxy, silty with abundant thin Sandstone lenses, burrowed in part

9561.25' - 9564' SANDSTONE: light brown to graybrown, fine to medium grained, sub angular to sub rounded, fair to moderate sorting, poorly consolidated, occasional thin, tightly cemented Sandstone lenses with siliceous cement, poor to fair intergranular porosity, light brown uniform oil stain, dull yellow fluorescence, instant yellowgreen streaming cut

9564' - 9565' SANDSTONE: medium brown to graybrown with dark gray burrows, fine to medium grained, sub angular to sub rounded, fair sorting, poorly consolidated, occasional thin, tight Sandstone lenses with siliceous cement, poor to fair intergranular porosity, light to medium brown uniform oil stain, dull yellow fluorescence, instant yellowgreen streaming cut

9565' - 9570' SANDSTONE: light to medium brown, fine to coarse grained, sub angular to sub rounded, moderate sorting, very poorly consolidated, fair to good intergranular porosity, light to medium brown uniform oil stain, dull yellow fluorescence, instant yellowgreen streaming cut

9570' - 9579.5' SANDSTONE: light to medium brown, fine to coarse grained, sub angular to sub rounded, moderate sorting, very poorly consolidated, scattered white to light gray tight Sandstone lenses with siliceous cement, fair to good intergranular porosity, light to medium brown uniform oil stain, dull yellow fluorescence, instant yellowgreen streaming cut, gray to gray green shale laminae at base

9579.5 - 9588' MICA SCHIST: black to greenblack with apparent dip to bedding, abundant fractures with slickensides, white hydro thermal vein filling, abundant rose quartz, biotitie, chlorite, feldspar and pyrite

Preliminary Announcement

for the

7TH INTERNATIONAL WILLISTON BASIN HORIZONTAL WELL WORKSHOP

April 25-27, 1999

at the

Delta Regina Hotel
Regina, Saskatchewan

(formerly the Ramada Hotel)

Preprint Order Form

Sixth International Williston Basin Horizontal Well Workshop

Please print

Name: ______________________________ Position: ____________________

Company: ____

Mailing Address: ____

City: ________________________ State: __________ Zip Code: ______________

Phone Number: ______________________ Fax Number: ____________________

Volume	Price Each	No.	Total
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